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ULTRA-DEEP DRILLING FOR GEOTHERMALS

TETRA TECH, INCORPORATED

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ULTRA-DEEP DRILLING FOR GEOTHERMALS

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13. ABSTRACT

Geothermal energy offers significant promise as a source of clean, widely available power. The first stage of its availability involves near surface sources; the second, abnormal thermal gradients; and the third stage, deep wells. This report assesses the potential and limitations of rotary drilling for deep geothermal systems. The assessment found that hot, dry rock geothermal energy produced from wells in the 35-40,000-ft range offers good potential to provide clean energy, a self-contained or independent energy source, no resupply for special problem maintenance systems, and the promise of economic competitiveness up to 100 Mw.

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DRILL CASING						
DEEP DRILLING						
PRESSURE						
FRACTURING						

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I. SUMMARY AND CONCLUSIONS

Geothermal energy offers significant promise as a source of clean and widely available power. Its general availability, however, is correlated with the three stages of geothermal energy development defined by Banwell and Meidar (1971).* As shown in Table 1, the United States is currently in the first stage, using geothermal energy developed from sources exhibiting surface manifestations. The second stage will involve the development of geothermal resources where the Earth's surface is estimated to process abnormal thermal gradients.* Eventually, the third stage of geothermal development will involve deeper wells, utilizing the normal thermal gradients of about 16°F/1000 ft that occur essentially everywhere on the Earth.

The third stage of geothermal energy development offers promising potential for providing a highly dependable, independent supply of clean energy. The problems that lie ahead in developing the potential for the widespread use of geothermal energy are scientific, technological, engineering, and economic. There is generally little scientific understanding of the nature and behavior of rock at the temperatures and pressures of these greater depths. The response of materials and the basic heat transfer processes necessary for exploiting such geothermal systems must be better understood through further research and development. Engineering developments, from drilling geothermal wells to developing underground conversion systems and circulating heated fluids back to the surface, offer problems of both an applied and theoretical nature.

A critical factor in the substantial research and development program implied in the third stage is development of a practical means of drilling wells in hot, dry geological settings to the depths required for further scientific research and technological development. A prime means of drilling such holes is the adaptation of rotary drilling technology to this task. Rotary drilling systems have been developed and successfully applied to the problems of exploration and production of petroleum and gas resources. The geological factors involved in such applications are significantly different in certain critical respects. Thus, considerable understanding and careful analysis are required to assess the potential and limitations of rotary drilling for deep geothermal system development. A substantial portion of the study undertaken by Tetra Tech was devoted to this assessment.

*Banwell, J., and Meidar, T., "Geothermal Energy for the Future," 138th Annual Meeting of the American Association for the Advancement of Science, Philadelphia, 1971.

The principal study conclusions are:

A. For hot, dry rock with abnormally high thermal gradients:

(1) Rotary drilling technology has been proven feasible for application in developing hot, dry rock geothermal wells up to depths of 20,000 ft in terrain where the thermal gradient is several times normal, leading to reservoir temperatures of 500-600°F at target depth.

Table 1. ESTIMATED U.S. GEOTHERMAL RESERVES

Fuel Price (mils/kwh)[a]	Reserves[b] (1000s Mw c of electricity)		
	Known	Probable	Undiscovered
2.90- 3.00	1[c]	5[c]	10
3.00- 4.00	30[d]	400[e]	2,000[f]
4.00- 5.00	?	600[g]	12,000[h]
5.00- 8.00	?	?	20,000[i]
8.00-12.00	?	?	40,000[j]

SOURCE: Rex, R.W., "Table of Estimated Geothermal Reserves" in Assessment of Geothermal Energy Resources, Committee on Energy Research and Development Goals, Federal Council for Science and Technology, 1972.

NOTES:

a. A fuel price of 2.90 mils/kwh is equivalent to a power cost of 5.25 mils/kwh. Assumptions include the following:
   - Recovery of 50 percent in in situ thermal energy in the hot-water reservoirs.
   - Power conversion efficiencies of 20 percent for vapor-dominated reservoirs and 14 percent for hot-water reservoirs.
   - Present costs and prices inflated by 5 percent/yr for the next 30 yr.
   - 22 percent depletion allowance for geothermal energy.
   - Energy price in present dollars.
   - Development by tax-paying entities.
   - 10 percent royalty to landowner (federal or state governments, or private landholders).
   - No severance taxes.
   - State taxes at a level no higher than the California corporate rate.
   - No increase in federal corporate taxes.
   - Cost of capital 8.5 percent.
   - Expensing of intangible drilling expenses.
   - No change in the depreciation rate for amortizing wells.

b. Note that the term "reserves" as used here differs from the more common usage.

c. Vapor-dominated reservoirs, primarily the geysers of California.

d. Deeper, vapor-dominated reservoirs, primarily in the Clear Lake/geysers area and high-temperature, hot-water reservoirs in Imperial Valley, California.

e. Deeper, vapor-dominated reservoirs and high-temperature reservoirs in the above areas plus Jemez mountains, New Mexico, and Long Valley, California.

f. Deeper, vapor-dominated reservoirs and high-temperature reservoirs in the above areas plus the remainder of the basin and range provinces of the western U.S.

g. Intermediate-temperature, hot-water reservoirs and deep, high-temperature, hot-water reservoirs in the above areas plus Hawaii and the over-pressured, hot brines of the Gulf Coast.

h. Same as above plus hot-water reservoirs in Alaska.

i. Hot, dry rock systems at less than 6 km depth over 5 percent of the western U.S., development based on hydrofracturing or cost-equivalent technology; cost estimate based on present drilling technology and could be reduced by new low-cost drilling technology.

j. Hot, dry rock systems, as in Note i, between 6 km and 10 km depth.

(2) Assuming a hydrofacturing or equivalent underground energy conversion technology, 100-Mw (or less) geothermal energy systems would definitely be more economical than nuclear power and would be competitive with oil-fired, conventional, electric-power generation at heavy fuel oil costs of \$5.10/bbl delivered. This assumption drives the economic viability of hot, dry rock geothermal energy development in a threefold way:

- It minimizes the number of well holes required initially.
- It provides adaptive expansion of underground conversion.
- It provides long-term (20-yr) use of initial well configuration.

B. For hot, dry rock with normal thermal gradients (16°F/1000 ft)

(1) Rotary drilling technology would have to be extended somewhat beyond its proven capabilities to produce the 35,000- to 40,000-ft geothermal wells necessary to provide heat reservoirs at 600°F. There are serious risks from a material technology and operations point of view in operating drill strings, logging systems, and other subsystems which make up rotary drilling systems.

(2) Even making the same assumption of a hydrofracturing conversion capability, the extrapolated costs and risks of geothermal systems in this case (based on rotary-drilled wells to 35,000-40,000 ft) do not offer competitive promise at this time. As rotary drilling technology is advanced within the petroleum production industry to wells beyond 30,000 ft, this conclusion would certainly have to be reconsidered.

(3) An alternative development of geothermal energy under normal gradient conditions involves drilling more but shallower wells at a site and using a binary fluid conversion technology, e.g., five pairs of wells at 18,000-20,000 ft at 340°F has been proposed. Rotary drilling is feasible although the number of wells required is large and drives the initial capital costs very high. Furthermore, the binary conversion technology does not offer the adaptive expandability of the hydrofracturing approach since the reservoir costs during the operating lifetime of a particular well configuration may be 3 - 4 yr rather than 20 yr, which would make the costs of such energy virtually noncompetitive. Indeed, based on a 20-yr life for the original reservoir, such a system would have power costs estimated at 15.5 mils/kwh, whereas a 3- to 5-yr life would drive costs to 21.5-28 mils/kwh.

In summary, hot, dry rock geothermal energy produced from wells in the 35,000- to 40,000-ft range offer good potential for meeting the following needs:

- clean energy,
- self-contained or independent energy source,

- no resupply problems/no special maintenance systems,
- promise economic competitiveness up to 100 Mw,
- reasonable extension/improvement of rotary drilling technology,
- development and proving of underground conversion concepts.

II. TASKS

1.0 TASK 1: GEOTHERMAL RESERVOIRS

Describe geology of geothermal reservoirs currently developed. Describe power plants used and energy conversion techniques currently used in geothermal installations. Describe operating problems encountered by energy conversion systems presently in operation. Describe operating characteristics, limitations, and research planned or recommended to improve systems presently in use. Examine extraction and conversion of heat energy encountered by deep (in excess of 25,000 ft) hole drilling and discuss differences between shallow and deep geothermal operations. Describe novel heat energy conversion techniques, methods, and systems proposed which might be particularly suited to deep geothermal installations.

1.1 Technical Approach

In this task, Tetra Tech primarily reviewed the literature; visited commercial firms, geothermal contractors, and government agencies; and conducted on-site investigations of geothermal operations in California. Some of the principal groups visited were: the United Nations (Resources Department), Cornell University, U.S. Geological Survey, and the National Science Foundation (RANN Program).

Materials gathered and reviewed included two particularly informative reports: one by UNESCO and one by Dr. George Kiersch of Cornell University, sponsored by the Air Force Cambridge Research Laboratory (AFCRL). Excerpts of the UNESCO report are included in this report as Appendix A. This material is not repeated in the text of this report.

1.2 Findings

Geothermal energy is currently extracted and converted into electricity in volcanic mountain areas in North America, the Cordillera of South America, northern Italy, Turkey, West Africa, Siberia, Japan, New Zealand, the Indonesian/Indian rift zone and island arc,

and Iceland. The volcanic terrain of these areas allows geothermal energy to be obtained from relatively shallow drill holes. However, such volcanic locations are usually remote and undeveloped, necessitating the conveyance of electricity over large distances.

In classical geothermal development, a natural hydrothermal fracture is sought. Heat is derived from underlying magmatic sources which are being replenished by rain water. The water filters into the hot rock from the surface and is heated by the deeper, fragmented, hot rock layers.

The production of geothermal fluids or gases from a subterranean reservoir is comparable to the production of oil and gas. Most known geothermal systems are hot-water reservoirs at high pressure and temperature. A few systems contain gaseous steam at saturation conditions, generally coexisting with water. The predominant form, gas or liquid, determines the production mechanism and dictates production practices.

The geysers in California, the Cordillera, and in Japan (Matsukawa) are predominantly steam. At the geysers, the reservoir pressure is about 500 psig, which reduces to about 125 psig at the well head. The turbines are designed to operate at 80-100 psig intake pressure. Each of the turbines at the geysers requires about 1 million lb/hr of steam to generate 55 Mw of electricity. The average steam production rate per well is 150,000 lb/hr. Thus, seven wells are required for each 55-Mw turbine at the geysers. As production of steam declines, new wells are drilled and added to the system. The average depth of geothermal wells is 7000 ft.

In terms of water, an average of 70-100 lb of water is required to produce 1 kwh of electricity. At approximately 10 percent efficiency, about ten times more heat is being rejected than is converted into electricity. Thus, a 100-Mw geothermal power plant requires up to 10 million lb of hot water or steam per hour (5000 yd^3/hr).

Of the hot water used, 90 percent must be returned to the environment, about three times more than for a nuclear power plant of equal size. Equipment for this recycling is expensive and a major cost factor in geothermal plants. Furthermore, economical cooling water is often unavailable at geothermal sites. Thus, cooling and environmental considerations become major problems in geothermal development.

In addition, steam contains from 0.12 to 2.2 percent noncondensable gases. Current design limits allow only 1 percent. Thus, removal of noncondensables further reduces the overall efficiency. Natural waters also contain varying amounts of minerals. Changing temperatures and pressures cause exsolution of the minerals, and thus, scaling, clogging, and corrosion or erosion of metallic system components.

Under conditions of inadequate water quality or insufficient temperature, artificial heat exchange fluids are used to convey the heat energy from the geothermal waters to the

expansion chamber of the turbine. An advantage of this method is that sealing, corrosion, and low efficiency are avoided. Fluids used as heat exchangers are freons, isobutanes, and other suitable organic materials. Heat exchange systems appear particularly suitable for small power systems.

In late 1972, the total installed electric geothermal capacity was about 1000 Mw, of which Larderello (Italy) and the geysers of California supplied about one-third each and Wairakii (New Zealand) supplied about one-fifth. Expected development by 1980 is approximately 2000 Mw, of which half will probably be produced from the geysers in California and used to support the San Francisco Bay area. Development is also underway in Central America, Iceland, Japan, Mexico, the Soviet Union, Imperial Valley in California, Turkey, Kenya, Ethiopia, Indonesia, and India. However, the amount of geothermal energy supplied to meet the world energy demand is negligible, and will continue to be in the near future.

The National Petroleum Council, in its 1972 report, projected the increase in geothermal energy supply by 1985 based on four sets of possible levels of U.S. domestic energy production. The most optimistic projection of geothermal energy increase is 19,000 Mw; the next most optimistic projection is 9000 Mw, if large land areas are available for prospecting without delay; the third growth estimate is 7000 Mw, or 1 percent of the U.S. electric energy requirements; and the least optimistic estimate is 3500 Mw.

Preexploration, detection, leasing and negotiating time, and pilot plant operation require about 10 yr in the development of a 100-Mw capacity reservoir – approximately the same amount of time required to establish a nuclear or conventional power plant. However, generating costs for geothermal plants in favorable sites, compared with those of nuclear or conventional power plants, are low (Table 2).

Table 2. COMPARISON OF PLANT OPERATING AND GENERATING COSTS*

Plant Type	Plant Site (Mw, electrical)	Plant Cost (dollars/kw)	Generating Cost (mills/kwh)
Geothermal (steam) 300°C rock (4 holes)	100	186	4.7
Geothermal (isobutane) 175°C rock (10 holes)	100	316	8.0
Nuclear (Eastern U.S.)	930	350	11.8
Coal-Fired Steam (Eastern U.S.)	950	250	13.3

*From Los Alamos Scientific Laboratory, The University of California, 1973.

1.3 Areas for Further Research

Since temperature increases with depth everywhere on earth, it is reasonable to assume that adequate heat conditions may be encountered in many places. However, deeper reservoirs still require additional research. Since oil and gas production has progressed from surface leaks to reservoirs below 30,000 ft, geothermal energy production could be extended as well. However, further research will be required in the artificial stimulation of fractures and heat exchange surfaces and in the provision of heat carriers such as water. All research efforts would have to consider the ultimate cost to the consumer together with the technological feasibility.

Even in terms of shallow geothermal development, the use of 12- to 24-in. inner diameter (I.D.) drill holes is being advocated. However, present drilling technology would have to be extended.

2.0 TASK 2: CONVENTIONAL DRILLING

Review and describe drilling methods, systems engineering practice, and equipment currently in general use in the oil industry and in the drilling of geothermal wells.

2.1 Technical Approach

In Task 2, Tetra Tech conducted a literature review, followed by discussions with drillers, contractors, government agencies, engineers, and geologists. On-site investigations were also conducted in connection with this task.

Much detailed information related to this task is contained in Appendix B and will not be repeated in the body of this report. The following discussion is a synopsis or overview of the findings.

2.2 Findings

The technical problems in conventional deep drilling systems are complex. Penetration of known or unknown sequences of rock strata by a hollow drill string is an ever new race with time and obstacles, which must be kept in check by a well-planned, finely tuned, and delicately balanced drilling system that can involve a million pounds on the hook and several thousand horsepower drawworks and pumpworks.

Conventional drilling involves counteraction of pressures and transport of cuttings by the drilling fluid; transmission of power and fluid by drill strings; holding open of the well under varying pressure conditions by casing strings; and logging and completion of wells, including cementing and perforating under great varieties of pressure, temperature, and mechanical/chemical conditions.

Conventional drilling is an effort of customized mass production. Most of the 30,000 holes drilled in the United States each year have very similar characteristics in terms of diameter, depth, drilling time, and cost. Consequently, drilling hardware is virtually standard.

Almost all conventional drill holes are made in sedimentary rock. However, because of

varying conditions of pressure, rock competence, porosity, etc., casing of varying strength is required. Moreover, casing strings have decreasing diameters so that they can be inserted through the preceding, emplaced casings. Thus, drill holes have a typical tapering, which can cause a serious reduction in the hole's diameter in cases of complex casing requirements. Unless the selected diameter at the head of the well is wide enough, a drill hole may be restricted in its terminal depth.

The planning and engineering of drill holes prior to spudding has, therefore, become an important part of drilling methodology. This planning is primarily based on past drilling experience. Use of computerized records and programs such as the Amoco Optimized Drilling Program allows the complete specification of drilling parameters and saves considerable time and money. During the actual drilling, calculation of hourly costs, costs for each foot drilled, and mechanical monitoring of the work plan and deviations in scheduling are measured and compared with averages of previous performance data. The computer programs and the experience on which they are based also specify and regulate the speeds of drill string movement and the pressures exerted on the casing and hole walls.

The predominant drilling method is rotary drilling, which requires the addition of a drill tool at the end of a rotating drill string. The drill bit must be changed periodically, necessitating the withdrawal and reinsertion ("round-tripping") of the entire drill string. At increased depths, a large part of the rig time is spent on the withdrawal, bit change, and reinsertion of the drill string. At 10,000 ft, for example, the process requires 10 hr; at 30,000 ft, it requires 24 hr. This time is essentially unproductive.

Because of the cost (time and money) involved in this process, methods have been sought to decrease or eliminate the round-tripping necessary in changing the drill bit. Research has been conducted on materials and bit configurations as well as on methods for changing bits through the emplaced drill string. Another operational variation is to rotate the drill bit by drilling fluid pressure at the bottom of a still-standing drill string. However, all the recent modifications have had little operational significance in the United States in comparison with the proven, standard rotary drilling method using diamond or hard-metal drilling bits.

In 1971, about 159 trillion BTU of oil and gas were produced in the world. Of this amount, 53 trillion BTU were provided for the U.S. economy. The oil and gas produced supplied about three-quarters of the total energy demand; the balance was comprised of coal, hydroelectric and nuclear power.

A large number of oil and gas tests have been made between 10,000 and 20,000 ft; increasing numbers, however, are being made in excess of 20,000 ft; and a few have been made as deep as 30,000 ft. These tests have been achieved without any significant changes in drilling methodology. However, the deepest drillings were performed under reasonably favorable geological conditions in sedimentary formations (Amadarko Basin, Oklahoma).

From an engineering viewpoint, drilling in igneous rock is generally easier than in sedimentary rock since casing and drilling fluid requirements (to counteract formation (pore) pressures) are less rigorous, although drilling rates are generally slower. However, oil and gas are seldom found in igneous rock and drilling in these formations is usually done for mineral deposits and construction.

To date, geothermal wells have not been drilled beyond 10,000 ft. Generally, under conditions of air drilling, heavy wear on drilling equipment occurs, and temperatures in excess of 600° F present critical difficulties in logging, cementing, and completion methods. Such high temperatures have been encountered only rarely in sedimentary drilling, whereas they are encountered quite regularly in geothermal well drilling. Thus, the geothermal gradient in the terrains that are being drilled appears to be quite variable. So far, geothermal drilling has been restricted to areas of high to extreme geothermal gradients, as is reflected in the comparison of about 3000 geothermal wells drilled to date in the world with several million for oil and gas (100,000/yr for about 20 yr).

2.3 Areas for Further Research

Conventional drilling has been specifically adapted for the needs and requirements of sedimentary rock penetration in search of oil and gas. Recently, the method is being stressed in progressing to even greater depths, without significant system changes. However, rotary drilling may have an optimum range and an optimum sector of application—20,000-25,000 ft in sedimentary rock. Because of exponentially increasing drilling costs with depth, deeper geothermal systems may require other means of penetration than rotary drilling to remain economic. Thus, further analysis must be done of the complex man-machine-lithosphere system. Also, further research must be conducted on new techniques and mechanical operations.

In geothermal drilling, the cheapest means of developing geothermal energy is by emplacement of shallow drill holes in high-temperature gradient areas, which are relatively scarce. Geothermal development requires the construction of wider diameter conduits than do oil and gas. Ideally, a minimum 12- to 24-in. I.D. hole should be available to support a steam turbine. Also, emplacement of heat exchangers at depth would be possible in wide-diameter structures.

3.0 TASK 3: DEEP ROTARY DRILLING OPERATIONS

Review and describe current engineering, testing, completion, and logging practices, techniques, and equipment used in deep (in excess of 25,000 ft) oil field drilling operations.

3.1 Technical Approach

After reviewing the literature on ultra-deep drilling operations, Tetra Tech examined a variety of wells in different geological locations to determine the current state of the art and the limitations within the technology and methods of operation.

3.2 Findings

Only a few wells have been drilled in excess of 25,000 ft. Because of technological and geological difficulties, costs increase exponentially with depth. Thus, the suitability of rotary drilling operations for deep geothermal exploitation is questionable. The problems and limitations of deep drilling are specified in the discussion of Task 4. In this task the general state of the art is described and the general technical problems and limitations inherent in the current engineering, testing, completion, and logging practices, techniques, and equipment used in deep drilling operations in the oil and gas explorations are outlined. To provide this overview, a variety of wells were examined in various geological locations: California, Oklahoma, southern Louisiana, southern Texas, West Virginia, and Wyoming.

For deep drilling, the knowledge of the target at depth is often limited. Seismic records of strata below 25,000 ft are weaker and less definitive than those at shallower depths. Ultra-deep drilling to date is generally carried out in sedimentary basins where extensive structural features can be predicted and defined.

In drilling deep wells for oil or gas, a sufficiently large hole at total depth is required to permit the setting of a production casing string. Such wells usually require several immediate casing strings, which in some cases reduce the hole size such that the overall objective cannot be met.

These and other limitations and difficulties can be seen in the following case descriptions.

California

Great Basins Petroleum
Tenneco 31-10X well
Total depth: 21,640 ft

The Great Basins Petroleum Company, an operator for a group of companies, has drilled the deepest well in California to date although two other wells, currently being drilled, are expected to exceed 22,000 ft in depth. All of these wells are in the Bakersfield area (southern San Joaquin Valley).

In sedimentary basins such as this, formation pressures and incompetent strata require protective casing strings. These sedimentary rock formations usually consist of layers of sandstone, shale, limestone, and combinations thereof. Pores created within these materials may comprise 10-30 percent of the bulk volume. The fluid in these pores is under pressure, and since most of the pore spaces are connected, fluid can move, under pressure, from one point to another. Under normal conditions, the fluid in the pore spaces is under a pressure equal to the freshwater or saltwater gradient for that depth. For example, the "normal" pressure of a formation at 10,000 ft is 4333 psi or 4650 psi for freshwater or saltwater gradients, respectively. Some formations have been known to have abnormal pressure gradients of up to 1.2 psi/ft of depth, or 24,000 psi at 20,000 ft. In oil fields, such pressures are usually expressed in equivalent heads of drilling mud in pounds per gallon (ppg). If at 30,000 ft a fluid in a pore is under pressure of 25,000 psi, a 30,000-ft drilling mud column with a density of 16.03 ppg would be required to balance this formation pore pressure. Thus, high-pressure formations must be cased and cemented off to permit further drilling.

Another factor that necessitates protective casing is induced formation fracturing. When drilling fluid densities become too high, certain formations with low-formation pore pressure tend to fracture on each side of the well bore. When this occurs, drilling fluid will enter the formation (lost circulation). The fracture gradient of certain formations is so low that the formation will not support the head of drilling fluid above it. A casing string must be set at such zones of lost circulation and cemented.

These drilling problems requiring the setting of casing strings are well illustrated in the deepest well drilled to date in California. Figure 1 shows the conditions encountered while the well was being drilled. The curve to the left shows the magnitudes (in equivalent mud density heads) of the formation pressures encountered. The actual drilling fluid density used is shown by the middle curve. The mud weight curve is always at a higher value than the formation pressure at the same depth; if it is not, the well could blow out of control. Formation fracture gradients are also shown. If the mud weight should become greater than the fracture gradient curve at some depth, fracturing and lost circulation would occur.

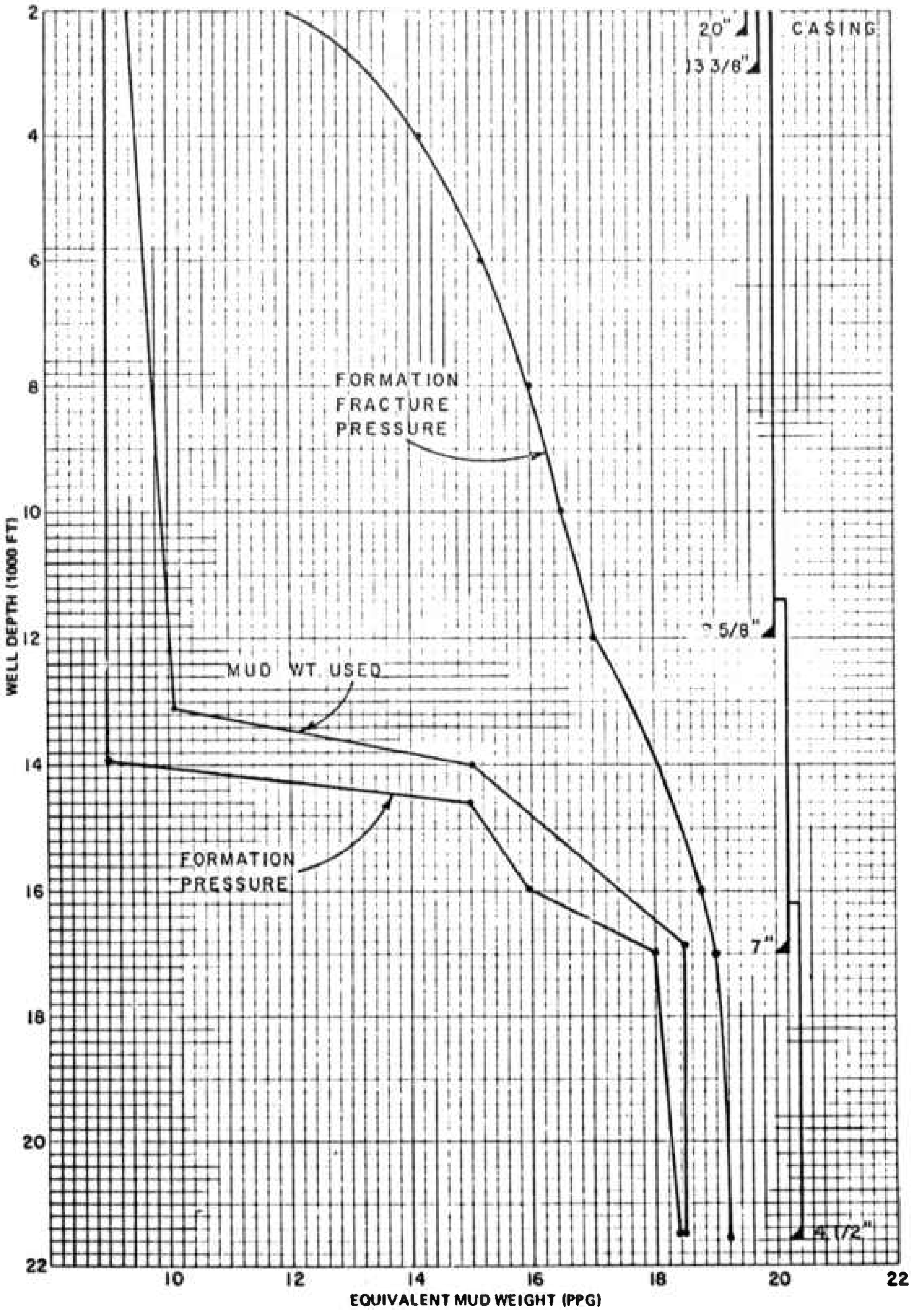


Figure 1. PRESSURE CONDITIONS IN DEEPEST CALIFORNIA WELL

Casing strings were set and cemented in this well. The strings are less than ideal, but this well was originally planned to have a total depth of 12,000-14,000 ft. At 12,000 ft, 9 5/8-in. casing was set because hole conditions were unstable and the drill pipe was almost stuck. The decision was made to set the 9 5/8-in. casing and drill deeper. At 17,000 ft, the required mud weight to prevent a blowout became so high that lost circulation and sticking drill pipe were experienced. These problems were solved by setting the 7-in. drilling liner, and drilling continued. Below the 7-in. liner, the hole was drilled to 21,640 ft without setting additional casing. The 4 1/2-in. casing was set as a gas production casing string. Eventually the casing restricted the size of the drill hole to such a degree that greater depths could not be reached.

Another problem in these high-pressure situations is the collapse of casing when emptied of drilling mud. Figure 1 shows that the pressure at total depth is about the equivalent of a 21,640-ft head of 18.4 ppg drilling fluid, equal to about 20,705 psi. If the 4 1/2-in. casing were completely emptied, approximately 20,000 psi of pressure would be applied to the outside of the casing–sufficient pressure to collapse all commercially available casing except small diameter casing such as a 4 1/2-in. outer diameter (O.D.) thick-walled pipe.

Temperatures encountered at great depth can create severe problems with drilling fluids, cements, and logging tools. Figure 2 shows the temperature versus depth for the California well. Formation temperatures are normally expressed as temperature gradients in degrees Farenheit per 100 ft of depth. In the figure, the temperature gradient from 0-14,000 ft is 1.3°F/100 ft, while at the 14,000-22,000 ft level it is increased to about 2.1°F/100 ft. Extension of such plots to depths of more than 50,000 ft reveals that temperatures in excess of 1000°F could be encountered. Use of present-day muds, cements, and logging tools would be impossible in such hot environments.

Oklahoma

El Paso Natural Gas Company
Easley No. 1
Total depth. 27,500 ft

This particular well is within a few miles of the world's deepest well. The geology, pressures, and temperatures for both wells are much the same and are shown in Figure 3. The important formation tops are shown on the left side; pore pressures are shown by the left-hand curves; and a range of fracture gradients are shown by the next two curves. Again, the mud density must always be just slightly higher than the pore pressures, but less than the fracture gradients. Therefore, all of the casing strings shown were required. A 16-in. string of surface casing was also set at 4000 ft.

Nearby, the Glover-Hefner-Kennedy Green 1-1 was drilled earlier. Figure 4 shows the mud weights used in this well. The pore pressure magnitudes were verified by the well kicking and trying to blow out at just below 21,000 ft.

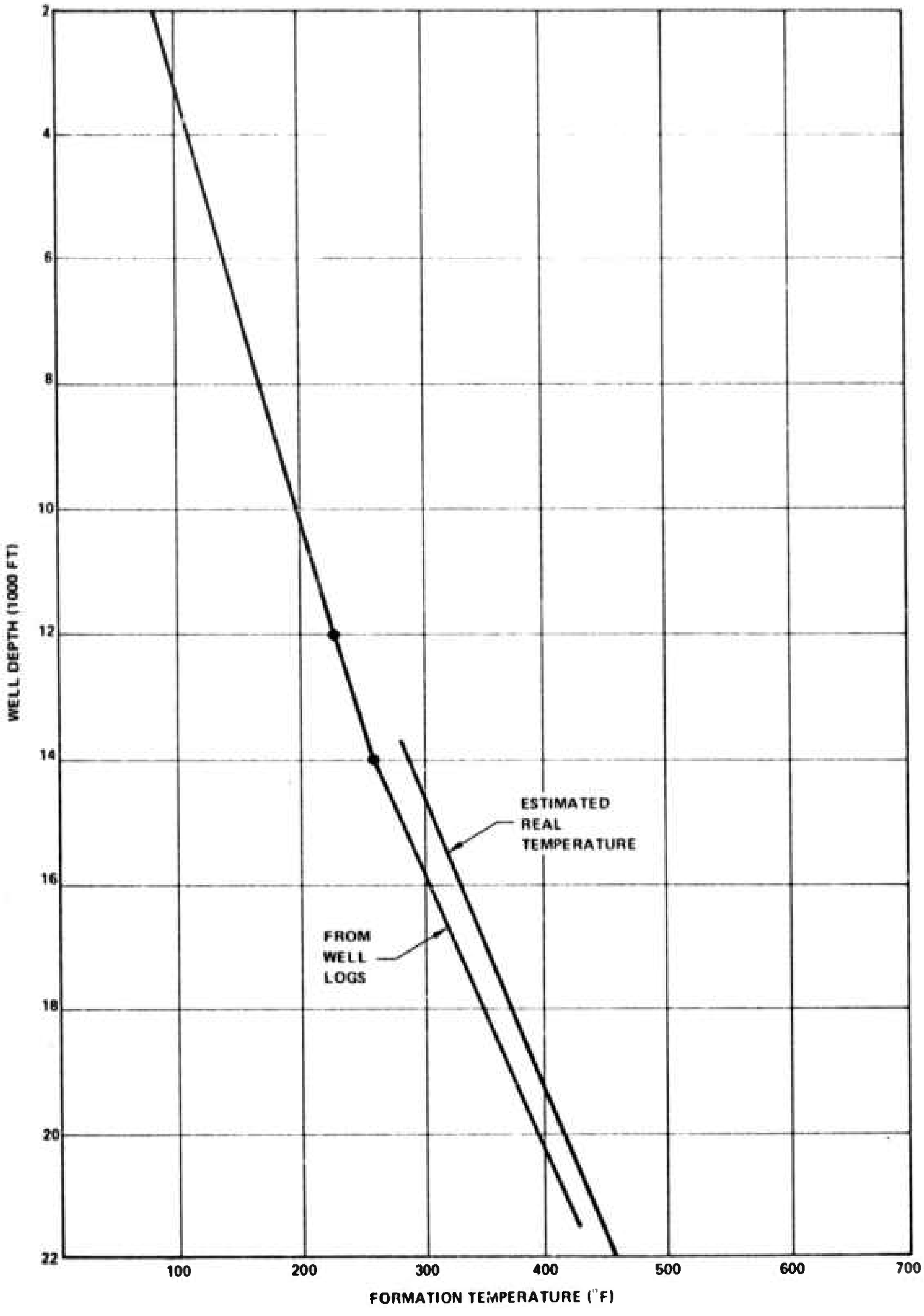


Figure 2. CALIFORNIA TEMPERATURE VS. DEPTH (BAKERSFIELD AREA)

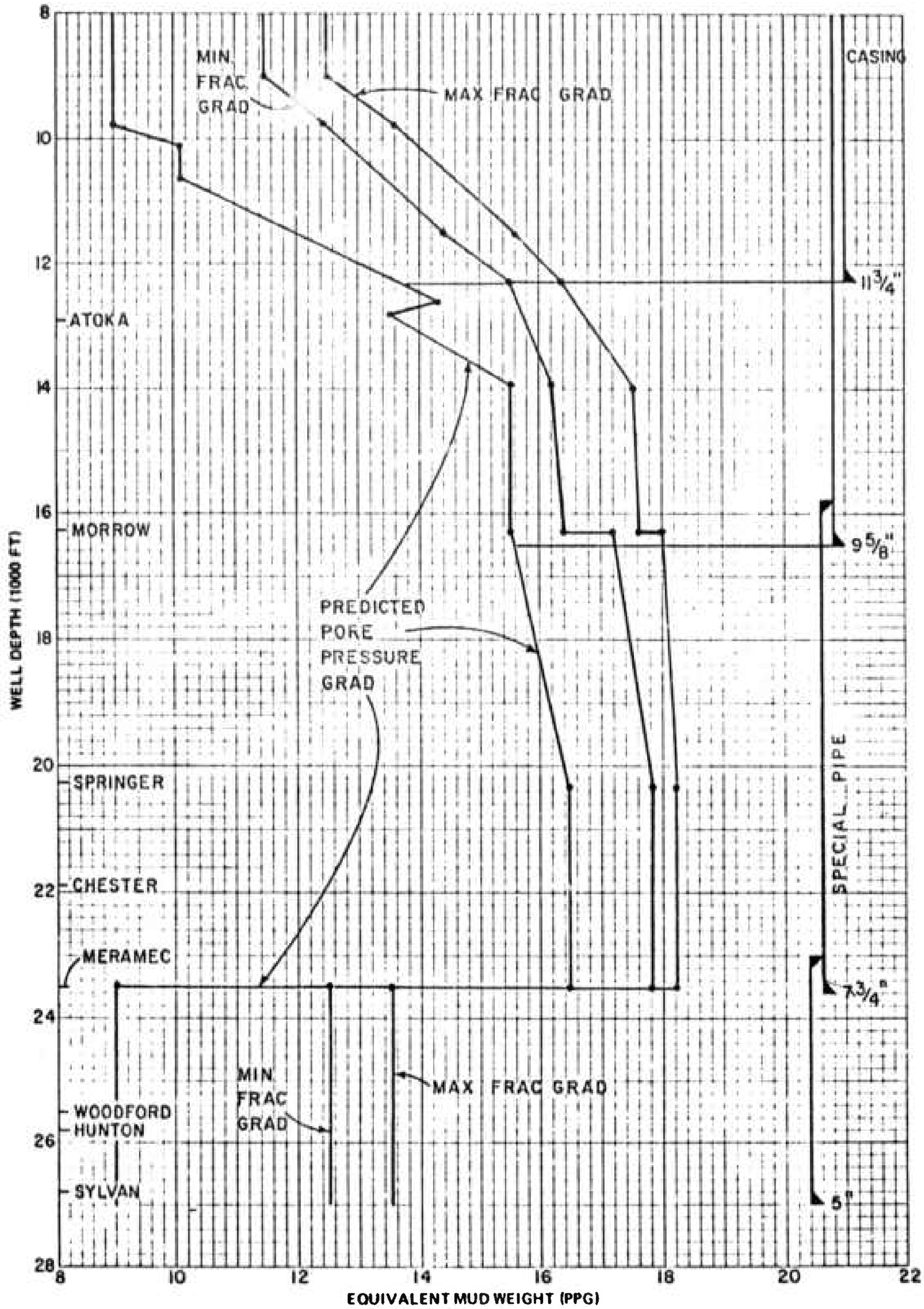


Figure 3. PRESSURE CONDITIONS IN EASLEY NO. 1, WASHITA COUNTY, OKLAHOMA

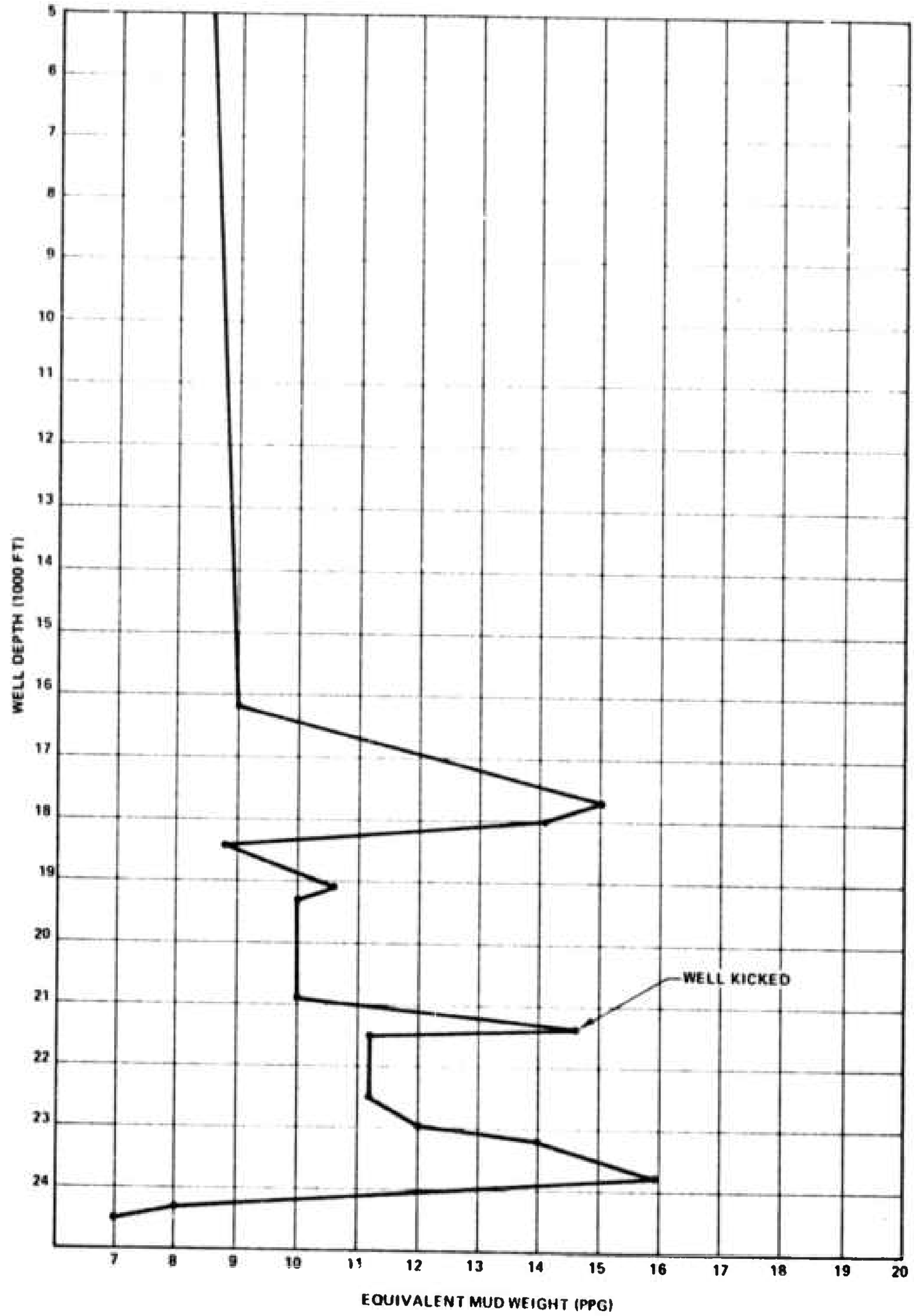


Figure 4. MUD WEIGHTS USED – GREEN I-I, BECKHAM COUNTY, OKLAHOMA

Temperature gradients in this area are not extremely high. However, a temperature of about 500°F was encountered in the Lone Star Gas Producing Company's Baden No. 1 well at 30,000 ft. The company was unable to obtain logs at the total depth of 30,050 ft because of the high temperature.

Louisiana (Southern)

Dow Chemical Company
Felix Bacque No. 1
Lafayette Parish, La.
Total depth: 17,500 ft

Drilling deep wells in this area presents problems somewhat unique and more troublesome than those of other areas. These problems result from relatively young sediments, which become very "plastic" with depth. Rock failure is of a plastic or ductile nature rather than brittle, as in hard-rock country.

Formation pore pressures sometimes become as high as the overburden or lithostatic pressure, which is created by the weight of all overlying sediments and the weight of the fluids contained in those sediments. For example, in this area the bulk density of sediments is about 2.0 gm/cc near the surface and increases to about 2.60 gm/cc at about 20,000 ft. Under these conditions, the lithostatic pressure equals about 17,300 psi at 17,500 ft. The pore pressure equals that of a head of 18.5 ppg drilling fluid, as shown in Figure 5. Thus, the pore pressure is about 16,840 psi at 17,500 ft, only 460 psi less than the lithostatic pressure at the same depth. Further, the fracture pressure equals about 17,300 psi at the same depth, about the same as the lithostatic pressure.

Again, the main problem is that in such pressure situations, the weight of the drilling fluid must be slightly greater than the pore pressure gradient (18.5 ppg) or a blowout will occur. However, under these conditions, when the drilling fluid pumps are turned on while drilling, the "equivalent circulating density" becomes greater than the fracture gradient at the bottom of the hole because of the friction as the drilling fluid flows up the annulus. This situation may cause fracturing, lost circulation, and eventually a blowout.

To prevent this situation from occurring, numerous casing strings are required, as shown in Figure 5. For example, the mud weight for a static mud column at 16,600 ft is 18.3 ppg. The fracture gradient at the 9 5/8-in. casing seat is about 18.8 ppg. Therefore, as the 18.5 ppg mud is circulated up past the 9 5/8-in. casing seat, the equivalent circulating density at that depth is very close to the fracture gradient. If the 9 5/8-in. casing had not been set and cemented, fracturing and lost circulation would have occurred somewhere above the depth of the 9 5/8-in. casing seat. The lower casing strings were required for the same reason.

In this area, it becomes impossible to drill by conventional methods below about

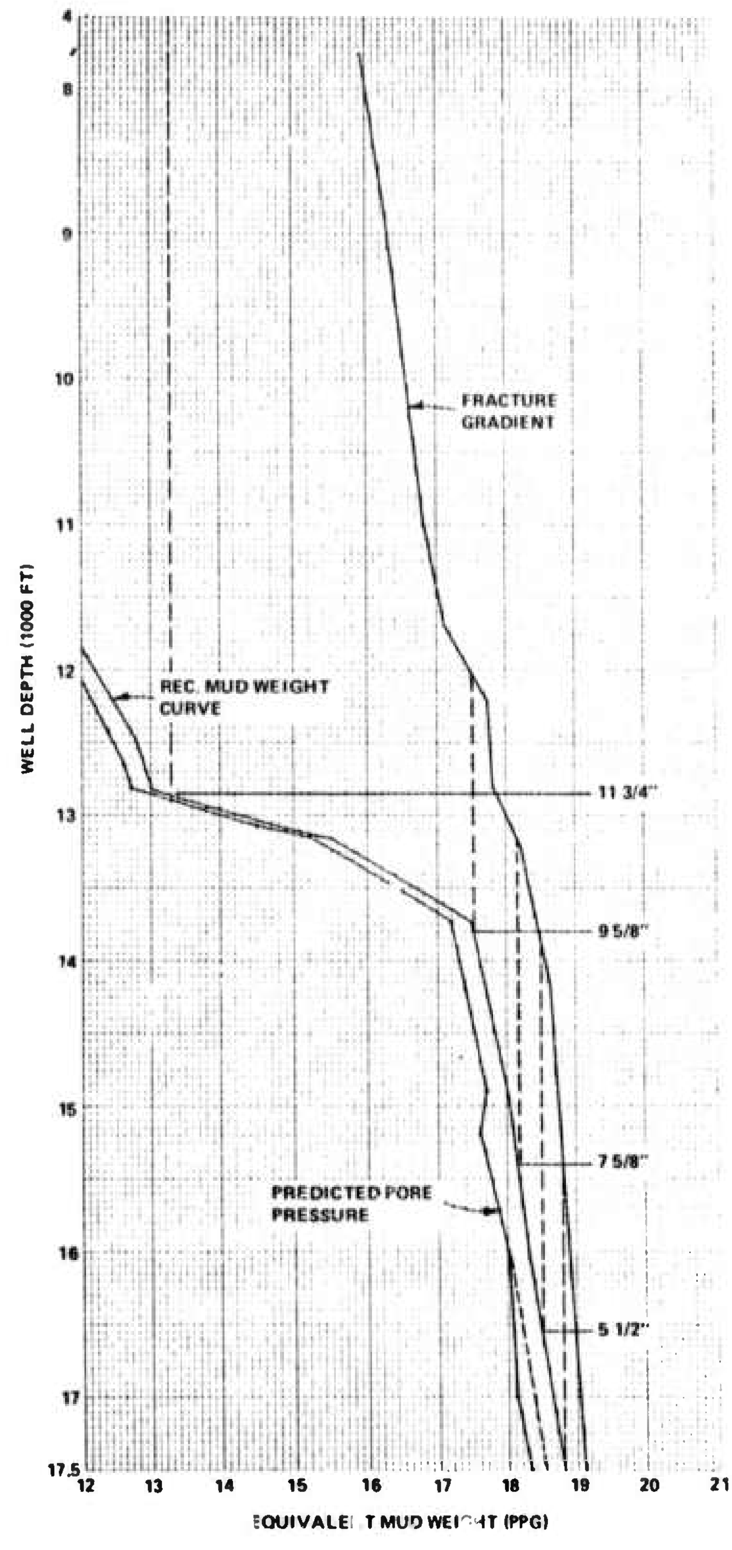


Figure 5. PRESSURE CONDITIONS – SOUTHERN LOUISIANA

18,000-20,000 ft. The pore pressure gradient, fracture pressure gradient, and lithostatic gradient all become equal. Extreme care must be exercised with the mud density. In many cases, the mud density is so critical that the well attempts to blow with the pumps off and lost circulation is then experienced when the pumps are turned on using the same mud weight.

Temperatures in this area are known to be high, although since no well has approached 30,000 ft in depth, ultra-deep temperatures are still undetermined. However, temperatures and pressures are sufficiently high to cause the formations to be very plastic. In this situation, if a well-bore or casing is emptied of drilling fluid, the formations tend to flow into the open well-bore or collapse the casing, where the hole has been cased.

Texas (Southern)

Shell Oil Company
Webb County, Texas (tight hole)
Total depth: 22,000 ft

Because this well is a "tight hole" and no information is released, no actual data are available. However, it is known that this is an area where high-pressure problems are severe and are similar in nature to those in southern Louisiana. Abnormally high formation pressures begin at relatively shallow depths and increase to greater than the equivalent of an 18.0 ppg head of fluid. The pressure profile, mud weight curve, fracture gradient curve, and casing program are all thought to be very similar to the southern Louisiana well.

However, one additional pressure problem occurs here because of the vast difference in pressures in various sandstone formations. For example, suppose that a sand exists at 12,000 ft and has a pore pressure equal to a 12.0 ppg head of fluid (7488 psi). As this sand was drilled, it would require 12.3-12.5 ppg fluid to control it while making trips for new bits. As drilling progressed to greater depths, sands and shales penetrated would require 18.0 ppg fluid to control the pressure.

Given this situation, a new problem exists. The sand at 12,000 ft is exposed to a head of 18.0 ppg fluid. The pressure of this static head is 11,232 psi, while the pore pressure of the sand at 12,000 ft is 7488 psi. A differential pressure of 3744 psi is directed from the well-bore into the sand, causing mud filtrate loss into the sand formation. When the drill pipe is stationary (as it is while making a connection for another joint of drill pipe), this differential pressure can cause the drill pipe to stick against the hole wall, referred to as "differential sticking" of the pipe. This is a severe problem and has caused many holes to be abandoned.

High temperatures are also severe in southern Texas. Temperatures exceeding 500°F have been encountered at the 18,000- to 20,000-ft level, with an average temperature gradient of about 2.5°F/100 ft. If this gradient is extended with depth, the temperature

should be about 1000°F at 40,000 ft. These high pressure and temperature conditions are such that plastic deformation or flow of the rocks is likely to occur, possibly causing the drill pipe to become stuck.

West Virginia

Columbia Gas Transmission Corporation
Well 9674T, No. 1
Mingo County, West Virginia
Total depth: 19,591 ft (20,000 ft test)

This Columbia Gas Transmission Corporation well is the deepest well in the eastern part of the United States. During the drilling of this well, there were four major problems: (1) crooked hole, (2) high pore pressures, (3) very hard rocks and slow penetration rates, and (4) near blowout.

This well was drilled using the following casing sizes and depths:

Conductor casing: 26 in. at 54 ft,
Surface casing: 20 in. at 1641 ft,
First intermediate casing: 13-3/8 in. at 6020 ft,
Second intermediate casing: 10-3/4 in. at 10,910 ft,
Third intermediate casing: 7-in. liner at 16,338 ft.

Air and/or natural gas were used as the drilling fluid in the well down to about 13,000 ft. However, if there is much water influx into the well bore, air is not desirable for drilling. Therefore, the shallow water-bearing strata had to be cased off. Using air or natural gas allows a bit to penetrate much faster than it will if water or drilling mud is in the hole. However, air or gas does not exert much static pressure on the drilled formations. For this reason, this particular well attempted to blow during drilling at 13,000 ft. Fortunately, the 10 3/4-in. casing was set deep enough to provide the fracture gradient required to control the well. Also, the 10 3/4-in. casing had sufficient burst resistance at the top to prevent an accident. A drilling mud with a density of 18.2 ppg was required to control the gas flow.

In this area, the formation pore pressures are normal down to the 13,000-ft level, increase rapidly to the equivalent of an 18.0 ppg head, and remain equal to a 16.0-18.0 head to depths of 20,000 ft or more. Because of the high mud weight required and the very hard rocks, penetration rates are very low. The following data (Table 3), a breakdown of some of the latter bit runs, indicate that penetration rates are very low and diamond bits drill faster than tri-cone insert bits.

Figure 6 shows the formation encountered in drilling this well. Depths of each age are also shown. Because of the hardness of the rock, considerable bit weight is required to drill,

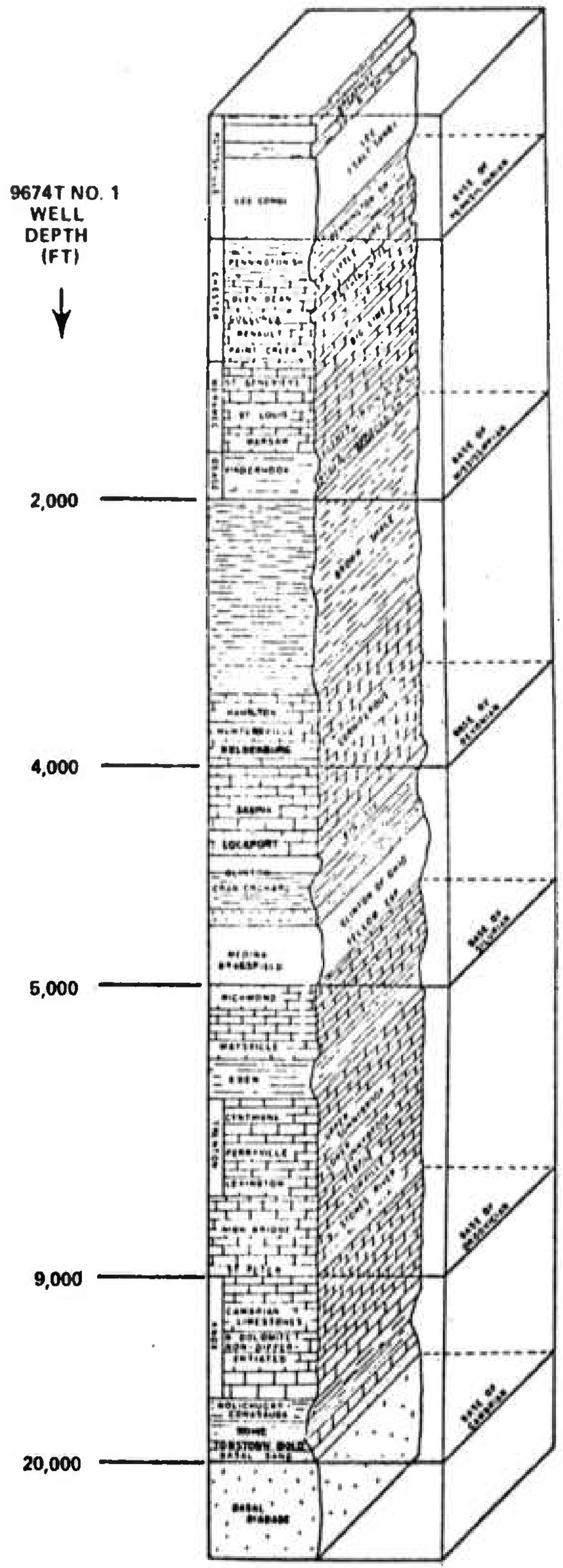


Figure 6. FORMATIONS ENCOUNTERED IN THE COLUMBIA 9674T NO. 1 WELL, WEST VIRGINIA

Table 3. DRILLING DATA

Bit	Size (in.)	Type	Depth Interval	Time (hr)	Footage (ft)	Rate (ft/hr)
88	6½	Diamond	18972-19265	149	293	1.96
89	6½	Insert	19265-19372	79	107	1.35
90	6½	Diamond	19372-19554	92	182	1.98
91	6½	Insert	19554-19582	21¼	28	1.32

leading to crooked hole problems. This particular well was so crooked that it was plugged with cement and redrilled very slowly and vertically. (Ultra-deep wells must be vertical or nearly so to prevent severe pipe wear.)

Temperatures of formations in this area exhibit a fairly low gradient. Figure 7 shows temperatures obtained while logging in West Virginia. The recorded temperatures fall on a straight line with depth. Actual formation temperatures are usually slightly higher than those recorded while logging because of mud circulation.

Wyoming

El Paso Natural Gas Company
Wagon Wheel No. 1
Sublette County, Wyoming
Total depth: 23,000 ft

Relatively few drilling problems occurred in drilling this well. Lost returns did occur but were caused by going in the hole too fast with a core barrel. Later, stuck pipe occurred with the collars at about 6400 ft while attempting to regain circulation. The major loss zone in this well was between 6000 and 6600 ft.

The hole was drilled extremely straight by running light bit weights. However, this resulted in low penetration rates and required many additional drilling days. The hole was drilled, logged, and then reamed out to 14 3/4 in. prior to running the intermediate pipe. This also required considerable additional drilling time.

The only problem that occurred in drilling the intermediate hole was fluctuating mud weight. Sonic logs from this well were interpreted and plotted, as shown in Figure 8. Pore pressure gradients were determined from these plots and then plotted, as shown in Figure 9.

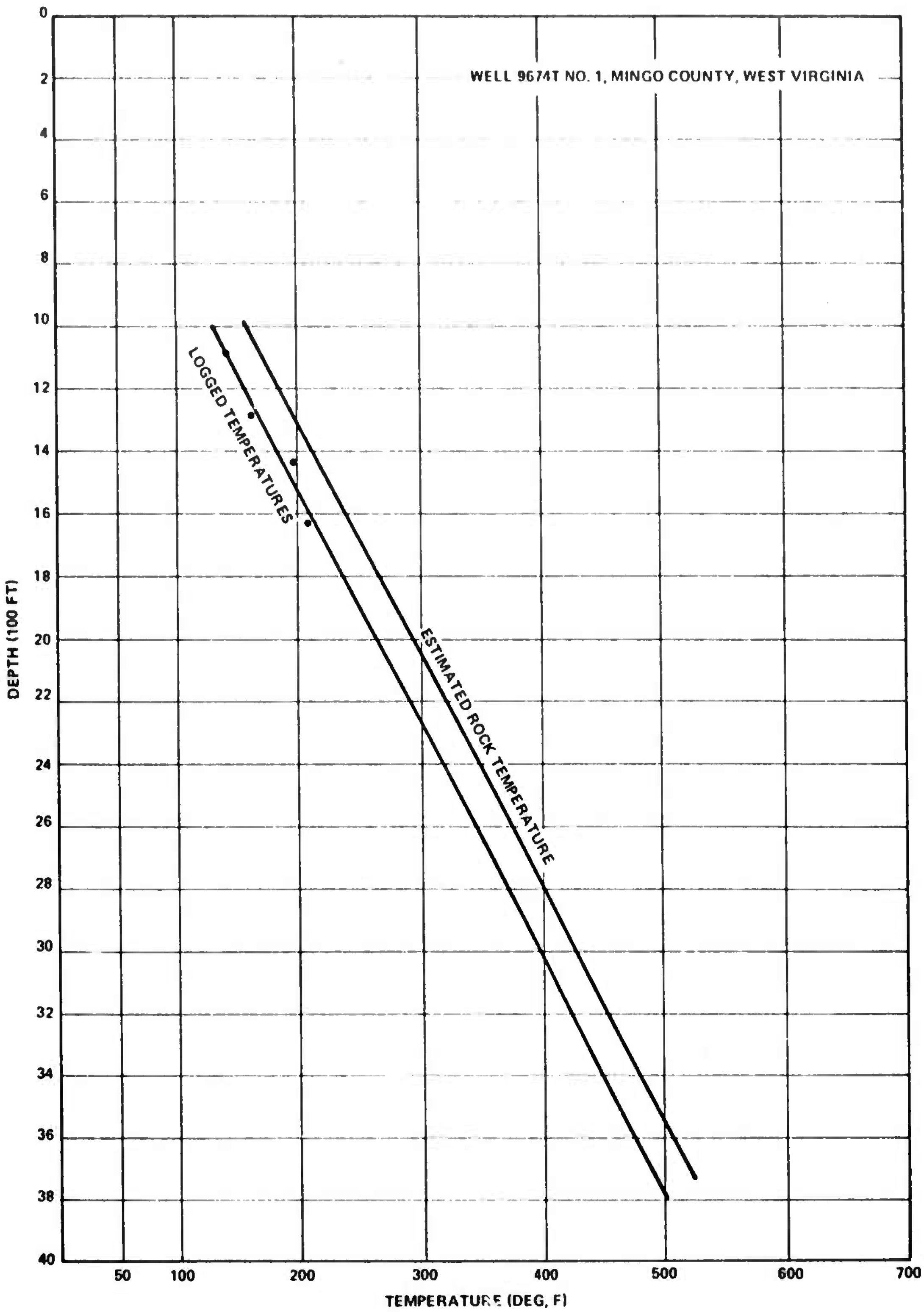


Figure 7. TEMPERATURE PROFILE--COLUMBIA GAS TRANSMISSION CORPORATION WELL 9674T NO. 1, MINGO COUNTY, WEST VIRGINIA

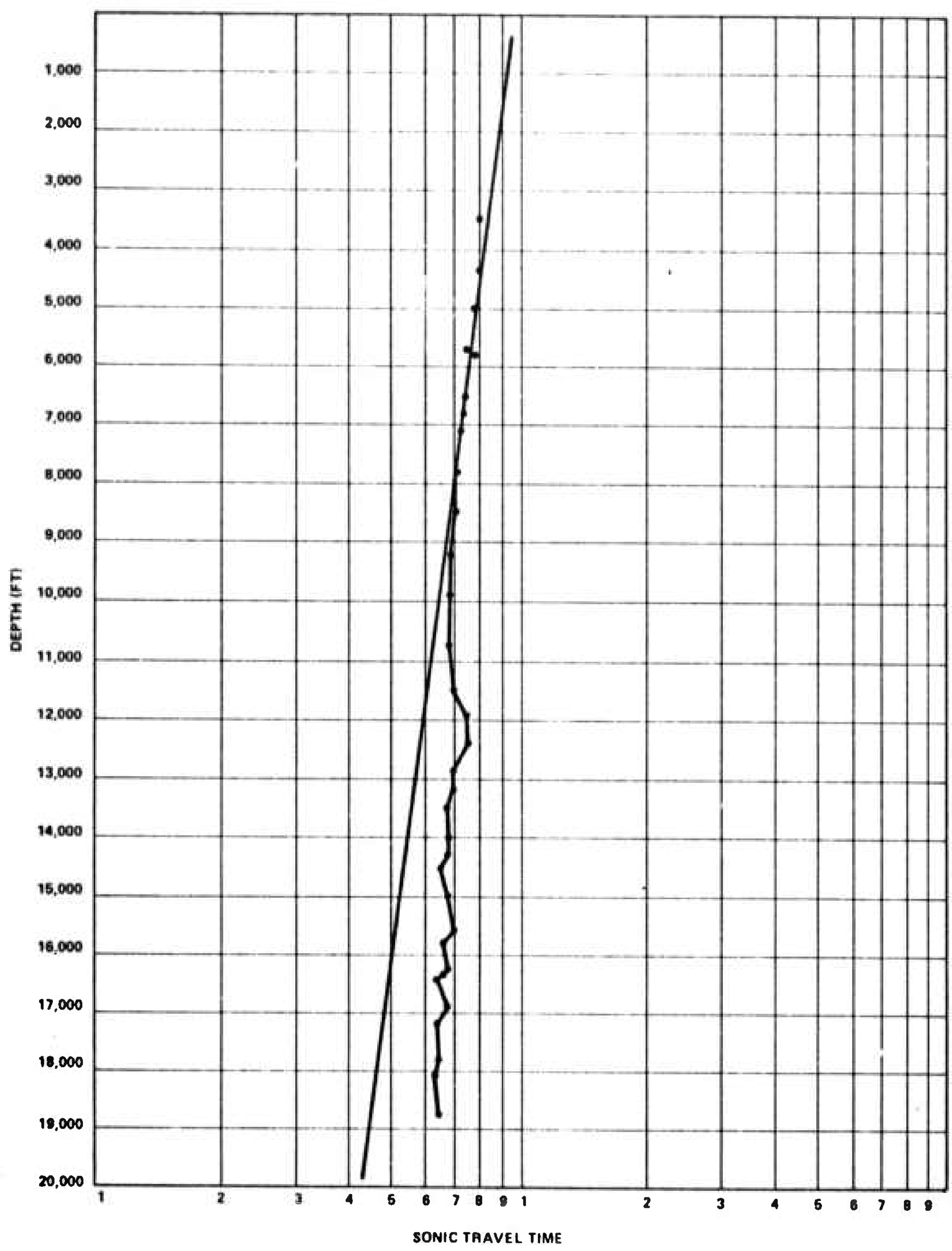


Figure 8. SONIC LOG PLOT – WAGON WHEEL NO. 1, EL PASO NATURAL GAS COMPANY

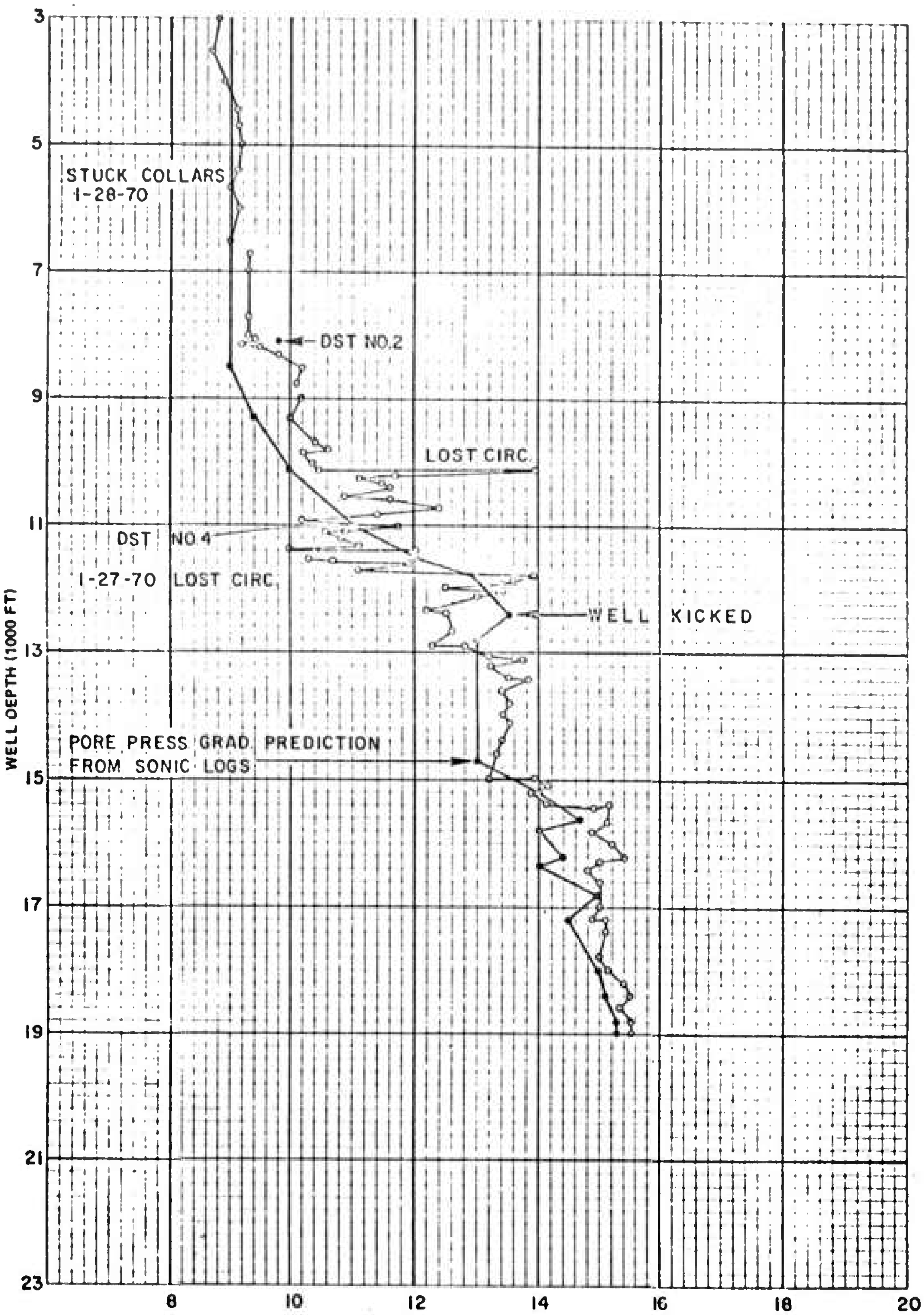


Figure 9. PORE PRESSURE GRADIENTS FROM SONIC LOGS AND ACTUAL MUD WEIGHT USED – WAGON WHEEL NO. 1

which also shows a plot of actual mud weights used in drilling the pilot hole. Note that the well was drilled under "under-balanced" or "near-balanced" conditions at all times, and that the drill stem test pressures agree with the sonic log pressure prediction. The mud weight fluctuated as much as 3.0 ppg or more at a specific depth. For example, at 10,200 ft, the mud weight changed from 10.5 ppg to 13.9 ppg over a very short interval and returns were lost.

These wide mud weight changes were attributed to (a) water entering the well bore and (b) water entering the mud system through the cooling and lubrication system on the mud pumps. However, since the mud head over-balanced the formation pressures, it seems unlikely that water could enter the well bore above 10,800 ft, the area in which the weight variations occurred. Thus, the dilution probably occurred through the pumps. Regardless, the shales were considerably washed out and additional cement was required.

However, these washouts were not the primary contributing factor to the cementing failure on the 10 3/4-in. intermediate casing—the first major problem encountered in drilling. The job was to run in three stages since lost circulation had occurred previously in the 6000- to 7000-ft depth interval and while placing the casing in the hole when the casing shoe was between 6800 and 8300 ft. The casing was equipped with such auxilliary equipment as guide shoe, float collar, stage tools, centralizers, and cement baskets.

On 29 April 1970, with the casing in place, the hole was circulated with 12.8 ppg mud that was cut with gas to 11.8 ppg in the flow line. The sonic log shows pore pressures equal to 13.2 ppg at 12,100 ft. Mud weights were still being cut from 12.6 to 11.6 ppg with gas just prior to the first-stage cementing operation. The first stage went as planned and the 392 bbl of slurry filled the calipered annulus to about 9150 ft, although according to calculations, the cement should have filled to only about 9400 ft. However, when hole washouts exist, all drilling mud is never displaced, and fill-up is higher than expected. Also, some contaminated lead slurry might have gotten above the first-stage tool at 8996 ft.

The plug was bumped on the first stage at 0145 hr on 30 April 1970 with the proper displacement. At 0300 hr on the same day, circulation was established through the stage tool at 8966 ft. The returning mud was reported to be uncontaminated by cement. However, the returning mud viscosity was 105 sec compared to 76-80 sec prior to the first-stage job. Since circulation was ceased only for short times, cement seemed to be the cause of the increased viscosity. The opening plug had dropped readily in the mud (inside the casing) to the lower stage tool.

At 0755 hr on the same date, the second-stage mixing began. The cementing volume was 2012 ft^3, or 360 bbl. The operation was normal except that when displacing, the closing plug never bumped and the second stage was over-displaced by about 86 bbl. Full returns were observed throughout the job and the displacement. At 1030 hr, the mud in the

pits had gelled to some extent. There was enough cement and displacement to circulate cement from the second-stage collar (at 5996 ft) to the surface, if this collar had been open. Had this been the case, cement returns would have been observed.

As a result of this cementing failure, the casing became buckled and holes were worn in it by later drilling. Later, when cementing the 7 5/8-in. liner, the cement "flash set" in the liner, causing another cementing failure.

Figures 10 and 11 show all the data used in planning such a well, for a total depth of 23,000 ft. Note that the objective is to have a 6 1/2-in. hole at total depth and be able to set a 5-in. casing liner. Temperatures at 20,000-23,000 ft are in the 425-450°F range, which is not excessively high. As previously stated, the only problems encountered in drilling this well were cementing, casing wear, and abnormal pressure.

As indicated by the previous examples, the general methodology of deep drilling in sedimentary rock is to simply extend standard drilling procedures; however, the setting of casing strings, excessive pressures and temperatures, and resulting effects on the system components become more severe with increasing depth. Yet, there are other methods of achieving deep, wide-diameter, untapered, underground construction. These methods include wide-diameter drilling as developed in volcanic rock at the Atomic Energy Commission's Nevada Test Site and ordinary shafts sunk by manned, semi-automatic or fully automatic systems.

These latter methods were also investigated and found to offer some promise for deep-hole environment. However, these latter methods lead by necessity to large-scale endeavors which require multiple uses to justify the increased expenditures.

3.3 Areas for Further Research

In terms of geothermal exploitation, the question is whether to construct many shallow wells or a few deep wells or a few wide-diameter, deep wells in igneous rock. Essentially the answer is one of economics.

Since the deep drilling has been based primarily on oil and gas explorations, one facet of deep drilling not reflected in the records is drilling in igneous rock. A study sponsored by the Atomic Energy Commission and conducted by Fenix & Scisson, Inc.,* was reviewed

*"Deep Hole Drilling Feasibility Study," Fenix & Scisson, Inc., Tulsa, Oklahoma, May 1969.

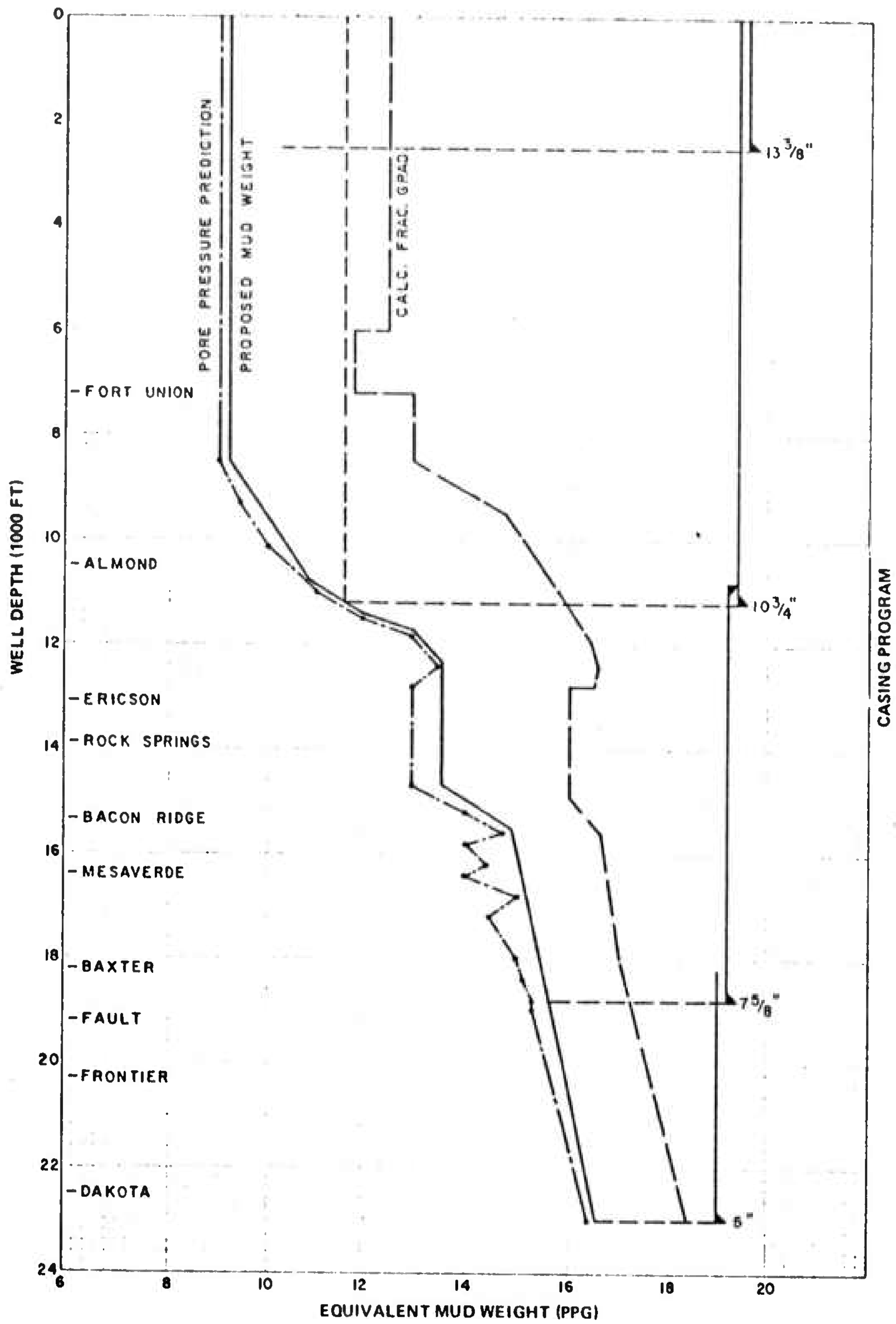


Figure 10. WELL PLANNING GRAPH—WAGON WHEEL NO. 1

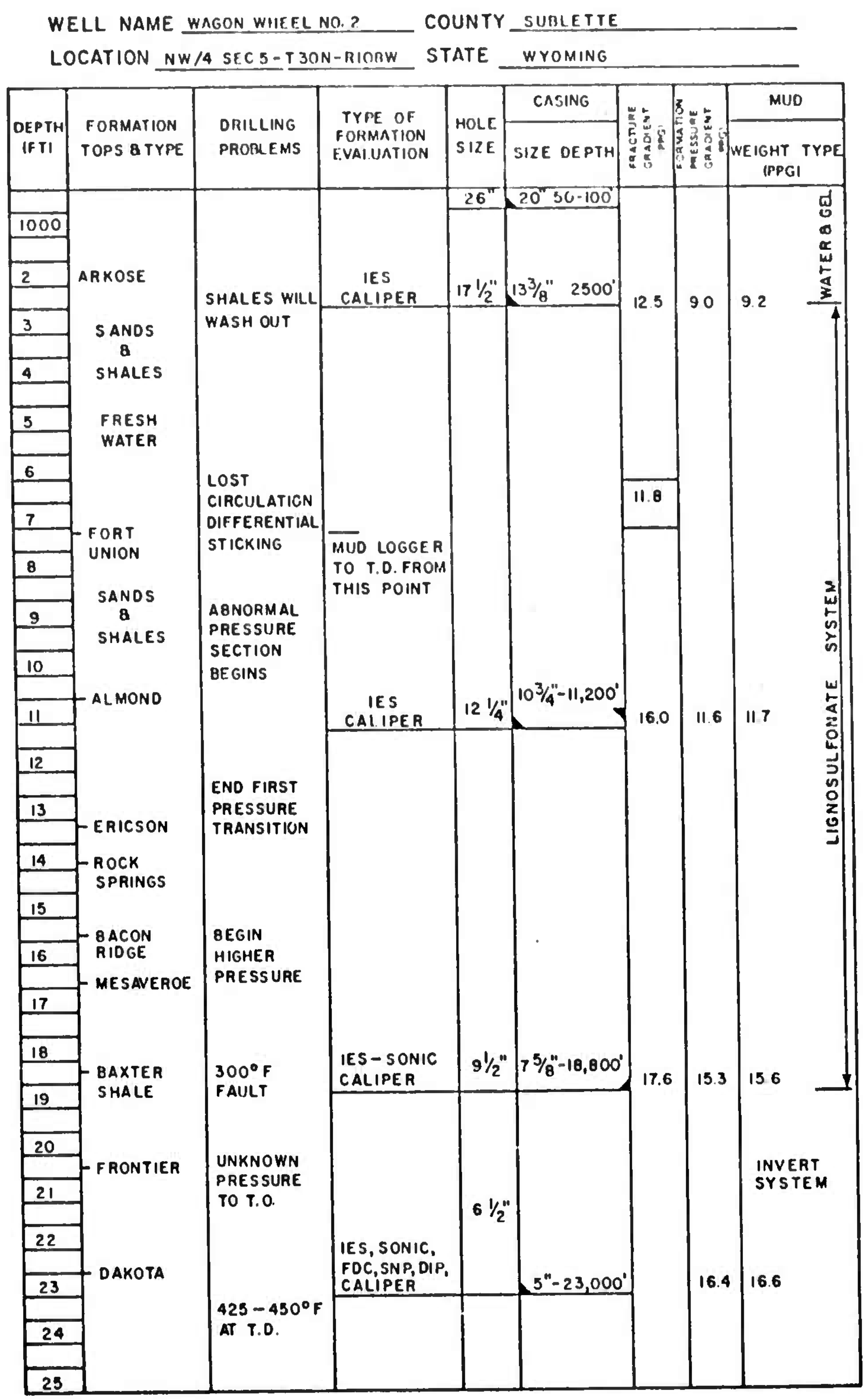


Figure 11. PROPOSED WELL PLAN OUTLINE

within this program. Based on it and other considerations, it is felt that deep drilling for geothermals should be concentrated in igneous terrain. This opinion is shared by Los Alamos Scientific Laboratory investigators, whose geothermal explorations center on granitic rocks and whose target depths are approximately 15,000 ft.

4.0 TASK 4: LIMITATIONS OF TECHNOLOGY

Describe limitations of currently available and used surface and downhole equipment, machinery, material, instruments and supplies imposed by depth, heat, corrosive fluids, geological nature and composition of the rock encountered, and other factors associated with ultra-deep drilling problems.

4.1 Technical Approach

Based on a review of the literature, discussions with people in the field, and investigations of drilling operations in various parts of the country with different but related conditions and problems, the limitations in current drilling practices center on the following parameters: depth, temperature, well diameter, pressure, rock form, structural barriers, economic barriers, and technological barriers. From information obtained in the earlier tasks, these parameters were examined and the problems involved summarized. Additional detailed information can be found in Appendix B.

4.2 Findings

Depth

One depth constraint in drilling a well by conventional methods is the length of the drill string which transmits the drilling energy and emplaces/retrieves the rock-breaking tool. This length has been proven to exceed 30,000 ft and may be as long as 50,000 ft under favorable geological conditions. However, the efficiency of drill string manipulation decreases rapidly with extended depth, causing exponential escalation of drilling costs with increased depths.

Temperature

The temperature limitation of all drilling operations to date has been approximately 600°F, with the exception of a few geothermal drillings which have exceeded 700°F. Deep wells that depend on downhole measurements for monitoring and control are especially vulnerable to high temperatures. Furthermore, drilling fluids, cements, and sensors become unstable at temperatures about 600°F.

Well Diameter

The drill hole diameter is generally small but should be large enough to allow the setting of casing strings required to withstand zones of high pore and formation pressure. The deeper the well, the more varied the lithologic column, and the greater the multiplicity of pressure zones, the larger the well diameter should be when spudding. However, the ability of a hole wall to withstand collapse under static pressure is a direct function of the casing diameter/thickness ratio along with the grade of steel used in the casing (Figure 5). To avoid a collapse in high-pressure zones in various rock types, several thick-walled casing strings may be required, which can reduce the well bottom diameter to zero.

As long as a well is filled with appropriately heavy drilling fluid, the pore and formation pressures can be counteracted. With the replacement of weighted drilling fluid by water or gases, however, the pressure can become prohibitive. For example, a pore pressure of 20,000 psi cannot be withstood by any commonly available, empty well casing except the highest grade steel, V-150, at a diameter/thickness ratio of 13. The more common P-110 steel needs a diameter/thickness ratio of about 9 to do the job (Figure 5), and such configuration is not generally available (U.S. Steel, for example, markets P-110 steel with a diameter/thickness ratio of 20-13 in outside diameters of 4 1/2 to 13 3/8 in.). Since pressures up to 50,000 psi must be expected in 50,000-ft deep wells in sedimentary rocks, the conditions of wide hole diameter, versatility of usage (removal of drilling fluid), and resistance to collapse are conflicting, creating a major problem in preserving adequate well diameters.

Pressure

Just as the temperature level and gradient limit the depth of a well, the pressure affects its diameter. High pressure can be handled using the technology currently available, but only in rather narrow (4 1/2 in.), cased wells, for example, the well plan shown in Figure 6. From 10,000 to 16,000 ft the pore pressure and formation pressure increase with increasing depth, requiring the setting of several interlocking casing strings. From 16,000 to 24,000 ft, the high pressures hold steady. At this depth, the well must be run on heavy, 18 ppg drilling fluid to counteract the pressure. Below 24,000 ft, the pore and formation pressures decrease to 13 ppg equivalent mud weight, and drilling can continue on a normal basis. Such abnormal pressures are considered normal in almost all sedimentary drilling.

These pressures have limited rotary well diameters and forced precautions and constraints. Pressure containment technology in large wells and excavations is only beginning. Presently, bulk construction plastics of exceptional mechanical properties are being investigated. Also, since high pore and formation pressures are believed to exist only in sedimentary rocks, drilling in igneous rocks is being further investigated.

Rock Form

High pore pressure in sedimentary formations represents a technological boundary to date. Until methods of pressure containment in gas-filled wells have been devised, deep drilling or excavation will be limited to igneous formations.

Structural Barriers

In igneous rock the primary impediment at any depth is jointing and fracturing of the rock, and it is highly unlikely that 50,000-ft granitic monoliths exist. However, convective water in fracture systems would be favorable for geothermal utilization of a deep well, even though its existence might endanger the drilling performance.

Economic Barriers

In any excavation process, the intended use of the structure will dictate its allowable cost. For example, a geothermal well should not cost so much that it makes the resulting electrical energy system prohibitively expensive. However, a structure intended for multiple purposes, such as drilling research and development, hardened communications systems, and the special needs of national defense, would allow the application of larger economical scales.

Technological Barriers

Drill *steel strength* is established both by the requirements of the drilling industry and the limitations of the current state of technology. Although the present drill steel length of 30,000 ft appears to be marginal and capable of breaking under its own weight, some drillers believe that 50,000 ft could be reached under favorable geological conditions. However, although depth does not seem to be a limitation at this time, there is no indication of plans to extend the design limit beyond 50,000 ft. The U.S.S.R. and some European countries are attempting to develop new alloys, but so far these alloys have not exceeded the capabilities of drill steels.

Available *casing strengths* are limited to the configuration of the most common casings required by the oil and gas industries. The ratio of outside diameter and wall thickness determines the collapse resistance, or strength, of a casing. This ratio is normally limited to the range of 40 to 10, with the most common ratios being about 20. However, to keep open wells under conditions of extreme formation pressure, as in ultra-deep drilling, casing with a diameter/thickness ratio below 10 would be required. Such gun-barrel equipment is technologically feasible but its custom manufacture makes it time-consuming and expensive to obtain. Currently, there is no effort to change this situation.

The *hook load* of current drill rigs limits the maximum casing weights to approximately 1 million lb. This limit may be raised gradually as designs for new and specialized rigs are improved.

The *drilling fluid* temperature barrier remains unbroken and discussions with leading research and development laboratories in Texas and Oklahoma indicate that no imminent breakthrough is anticipated. To date, all water-based or oil-based drilling fluids become useless at temperatures over 600°F.

As with drilling fluid, *cement* also becomes useless at temperatures over 600°F, and a breakthrough is not anticipated to date. Currently, at temperatures over 600°F, the water in the cement boils and evaporates before setting can occur; the cement powder is then blown out the steam wells. In California, some wells have been successfully cemented at temperatures above 700°F by saturating the cement with modifying chemicals. However, an application at extended depths, with the inevitable delay between preparation and emplacement, is highly questionable.

The *logging tool* industry has been trying to extend the reliability of logging tools in temperatures over 500-600°F. Currently, it is being claimed that reliable performance in temperatures up to 1200°F, at least within several hours of tool insertion, is within reach.

Other barriers dictated by the equipment, such as energy deliverable at bottom and drilling cost, are also areas for further research and development activities. To date, energy deliverable at bottom decreases with depth, while drilling cost increases exponentially.

Expansion of technological limitations cannot be expected to occur rapidly or without a demand to fill a need in the drilling industry. In terms of geothermal development, the best approach seems to be circumvention, using current technology and carefully selecting locations, depths, and rock formations.

4.3 Areas for Further Research

In addition to the extensions of the current technology that have been mentioned in this discussion, new techniques must be investigated. Some advances can be achieved within the current technology, but 50,000 ft would remain a maximum depth. The ultimate research effort, then, must be in drilling beyond that depth. In addition, geothermal development remains even more limited than oil or gas drilling. These research areas for geothermal development have been indicated in previous sections.

5.0 TASK 5: EXTENSIONS OF CURRENT TECHNOLOGY

Review extensions of current technology to new or proposed drilling techniques, methods, and practices for ultra-deep wells and deep wells in impermeable rock. Describe laboratory and field experiment experience and results. Summarize recommended research requirements needed to extend the usable life, reliability, and range of drilling system components, materials, fluids, instruments, and machinery used in drilling into areas of high geothermal activity.

5.1 Technical Approach

Initially this study was based primarily on gathering and compiling information. This literature review was followed by discussions with knowledgeable agencies and industries throughout the country and by visits to various drilling sites. However, each group was specialized in the mode of operation, depth, and rock form pertinent to its particular goal. Yet, the information exchange was profitable and added a new dimension to the present status and capability of the contributors and technology of the field in general. The overall view obtained provided the basis for the findings contained in this section. Additional detailed information can be found in Appendix B.

5.2 Findings

Several methods of deep hole making are reviewed and introduced in the following paragraphs. These methods are shown in Figure 12.

Single Drill Hole

The typical deep excavation structure is a single drill hole, generally rotary drilled in sedimentary rock (Figure 12A). Although the single drill hole using the rotary mode is the most economical means of deep penetration, it suffers from a number of drawbacks. In sedimentary formations, the diameter of the drill hole is generally not constant, but decreases with depth because of the casing required. The planned terminal depth usually cannot be exceeded by a "change" in drill plans because the diameter becomes too narrow. Furthermore, the hole must remain filled with drilling fluid at all times to counteract the pressure on the well bore, thus restricting the utilization of the well. Also, any control over the well and the penetrated formations is limited by the confinement of access through the casing string and its attached safety and operational mechanisms.

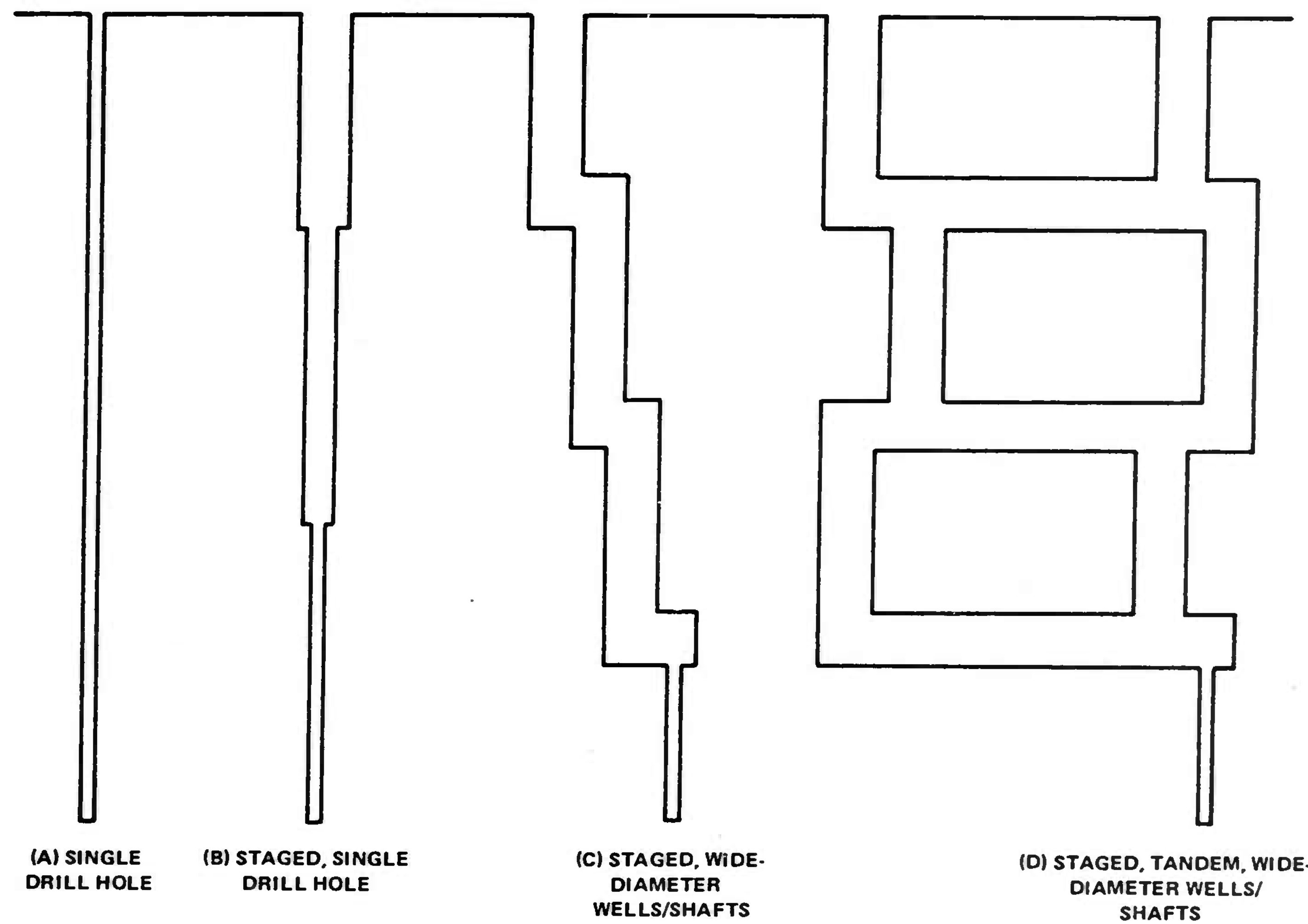


Figure 12. CONCEPTS IN DEEP HOLE MAKING

However, there are several ways to increase the drilling efficiency in igneous rock. The rotary method of rock disintegration has been modified by hydraulic water jets, hydraulic and turbine bottom hole motors, and wide-diameter rotary drills. These modifications result in increased rates of hole making, but without changing the basic drilling system, which is still at 30,000 ft and ultimately limited to 50,000 ft. Also, some recent development efforts have focused on improved, novel drill bits, which are expected to extend the bit life and reduce round-trip requirements for the drill string. However, none of these improvements will extend the depth of a single well beyond 50,000 ft within the foreseeable future.

Staged, Single Drill Hole

Staged, single drill holes (Figure 12B) allow the use of different technologies in completing the hole, including allowing for time lapses between stages. This approach is being pursued in the U.S.S.R. First, conventional rotary methods are used, followed by automated rotary drilling to 30,000 ft, which entails a more rapid handling of the drill string above the ground. The well may then be completed and re-entered when more advanced turbine drills are available to bring it to target depth.

Using wide-diameter drilling or shaft sinking during the first stage of such a drilling operation would allow a reduction of drill string round-trip time and, through increased efficiency, of drilling cost. The costs of a wide-diameter first stage are no higher than ordinary rotary costs, and the staging might allow the cost increments to be kept more linear than exponential. Other advantages of the wide-diameter hole are discussed below.

Staged, Wide-Diameter Hole/Shaft

A staged, wide-diameter hole/shaft (Figure 12C) is one step beyond the staged hole with a wide-diameter first phase that was just described. In this case, the wide-diameter hole continues throughout the shaft and stages.

A wide-diameter hole can be produced by rotary drilling, semi-automated or automated drilling, or blasting and mucking techniques. The advantages of the wide-diameter hole are: manned access to the well bottom, the possibility of horizontal tunnels, staging/stacking of several shafts on top of one another, extended depth range in add-ons, and a constant, large diameter.

Staged, Wide-Diameter, Tandem Holes/Shafts

A staged, wide-diameter, tandem system (Figure 12D) offers the greatest possibility of utilization and development. About 50 percent of the broken rock can be hoisted mechan-

ically, after collection downhole, rather than by flotation in drilling fluid. The system allows for dual access to most points and ventilation and refrigeration. Most important, every level can be established as a new working level, thereby reducing hole-making costs as compared with one-hole deep drilling. Since construction methods can be employed and most equipment in the shaft can be man-operated, this approach offers a high probability of completion in accordance with plans.

Ultra-deep drilling by rotary methods becomes prohibitively expensive. For example, under the right geological conditions, a well could be rotary drilled to 50,000 ft, and would cost about $20-30 million. Of this cost, the following percentages would be spent on the respective depth increments:

Depth Interval	Cost %
0 - 10,000	3
10 - 20,000	6
20 - 30,000	13
30 - 40,000	26
40 - 50,000	52

However, if a dual-shaft system with staging and wide diameters were used, 10,000-ft wells could possibly be stacked below 50,000 ft while keeping drilling costs low. Although this approach could conceivably decrease the drilling costs of ultra-deep drilling, life-support systems would also be necessary at the various staging levels, which could increase the cost of the total system. Thus, detailed cost effectiveness analyses of such a system should be conducted as part of any further research efforts.

The implications and conclusions derived from an examination of these drilling methods are summarized as follows:

1. No one practical and operational hole-making technique should be ruled out as a potential possibility for ultra-deep penetration. Techniques include rotary drilling and its modifications—turbine, wide-diameter, and high-pressure jet and rock-melting drilling; automated, semi-automated, and manual techniques; and manned stations, combinations of drilling and blasting, and hoisting of rock.
2. No individual hole-making technique known is believed to be capable of economical, ultra-deep penetration; combinations of techniques are believed necessary to provide the performance and economic levels required in a competitive market.
3. The total hole-making process must be planned and defined prior to beginning the operation. If staging is to be used, each stage must be integrated with every other section.
4. Initially the well should be as large as possible in diameter and the width should be decreased as little as possible so that the hole is not restricted at great depths.

5. Tandem wells should be advanced simultaneously and within a short distance of each other so that they can be linked at any level. Under certain conditions, the advancement of two communicating wells to extreme depths can cut costs, allow for special techniques useful in geothermal development, and increase the utilization of the well.

5.3 Areas for Further Research

As stated previously within this section, the tandem shaft system with staging and wide-diameter holes should be investigated further, with emphasis on a cost-effectiveness analysis. Drilling techniques and advancements and life-support requirements and systems should also be investigated, including the effects of various geological conditions on these.

6.0 TASK 6: NOVEL TECHNIQUES

Review novel drilling techniques for extending the depth range of drilling operations. Describe currently known limitations of techniques and equipment considering factors mentioned in Task 4. Recommend areas of research required for application of novel drilling techniques to deep drilling operations.

6.1 Technical Approach

In this task, Tetra Tech drew upon the findings of the previous tasks, primarily the state of the art and current research advances in ultra-deep drilling within the petroleum industry (rotary drilling in sedimentary rock); literature, primarily from the Eighth World Petroleum Congress; and a comparative cost analysis for geothermal, conventional (oil and gas), and nuclear energy, which is presented in Section III of this report.

6.2 Findings

As discussed in detail in other tasks, the most significant problems in ultra-deep drilling are high temperature and pressure. These problems, the state of the art, and new developments (potential and currently under investigation) have been discussed in detail in other tasks and in Appendix B. A synopsis of the novel techniques being developed in rotary drilling, particularly in reaching greater depths, follows.

Tubular Goods

Special techniques, such as running liners to bottom on drill pipe, cementing them in place, and then tying the liners back to the surface, will be required because of the high tensile loads imposed upon the upper portions of full, long casing strings. Additional casing sizes and high-strength grades of steel will need to be developed.

Drill Pipe

Again, higher strength steel has been developed for drill pipe, and additional grades and sizes will need to be developed as the need arises. In ultra-deep drilling, because of the

instability of the rock, it may become difficult, if not impossible, to remove the drill pipe for bit changes, logging, or casing. One of the novel developments foreseen is one-way drill pipe, which is advanced to the greatest attainable depth and is then cemented into place, after removal of the drill bit from the inside of the pipe. The drill pipe then takes on the role of the casing string.

Drill Bits

Many novel drill methods are being developed, tested, and refined. Among these methods are: erosion (spark), explosives, forced flame, jet piercing, electric disintegrating, pellet, turbine (1 stage), plasma, electric arc, high-frequency electric, fusion, lasers, electron beams, and ultrasonics. Various combinations of these drilling methods are also under investigation. Figure 13 shows the rates at which wells can be drilled in medium-strength rock using these various methods and tools.

Bit Trip Times

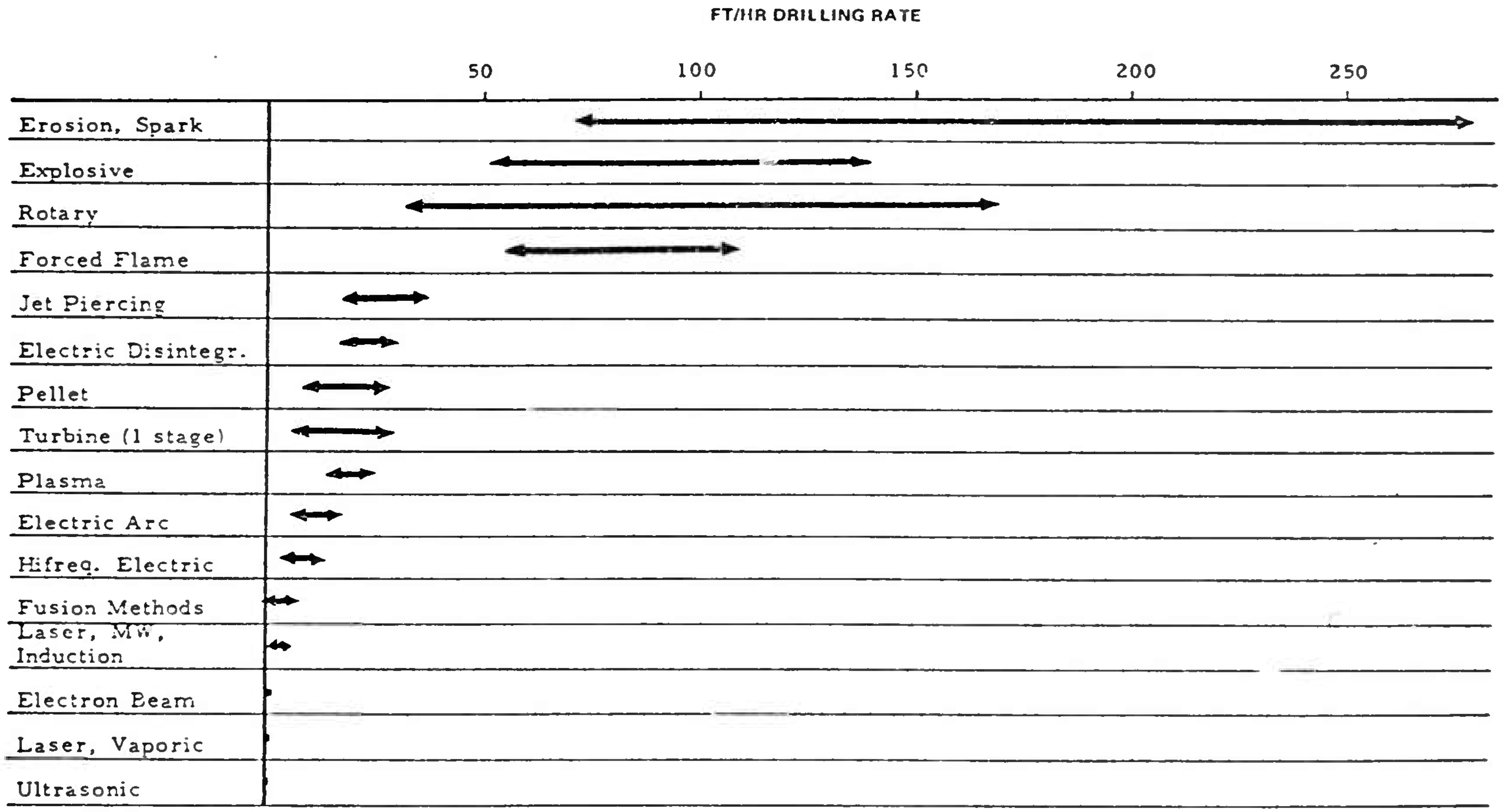
Time spent in pulling a worn bit out of a well, replacing it, and running the new bit back in the hole, is wasted as far as actual drilling is concerned. To date, the elimination of round trips has not been possible. However, some of the ideas for decreasing both the number of trips and the time involved are: better bits that drill faster and longer, bits that could be replaced by wire line through the drill pipe, and a means of pulling longer stands of drill pipe. For example, trips could be faster if the drill pipe could be rolled up on a spool, or pulled in 1000-ft segments rather than the conventional 93-ft stands.

Drilling Rate Vs. Overall Drill Time

In ventures such as ultra-deep drilling operations, which involve extended drill times and distances, even minor improvements of the effective drilling rate can lead to enormous cost savings. Further research could produce such savings.

The N x 1000 Ft Drill Pipe Segment

In deep ocean drilling, it has been suggested that long drill pipe strings could be hung in the moor pool of the ship, thus minimizing trip time. In land drilling, large segments of drill pipe can be pulled intact, provided the derrick is tall enough; the pipe can be flexed or rolled; or the derrick can be extended at depth by a shaft that is accessible at bottom to man or equipment. To date these have not been done. If only a fraction of the savings in trip time could be converted into active drill time, total rotary drill yields could be increased



Mauer, W.C.; Heilhecker, J.K.; and Love, W.W., "High Pressure Jet Drilling," SPE-3988, Society of Petroleum Engineers, AIME, 1972.

Figure 13. ESTIMATED NOVEL DRILLING RATES IN MEDIUM-STRENGTH ROCK

tenfold. A combination of high-capacity derrick and a wide-diameter well or shaft could be utilized to increase the effective drill time of a modern drill rig by that much.

Drilling Muds

Research is currently being performed at the three major mud company research centers in Houston, Texas, as well as in major oil company research centers. The objective is to develop drilling fluids to be used in deep wells with bottom hole temperatures of over 700°F. The main problem with drilling fluids at high temperatures is that they tend to thicken or solidify at the bottom of a deep well during a round trip. Some possible solutions are: new highly stable polymer water-base muds, new oil-base muds, surface refrigeration of the drilling fluids, and faster trip times.

Cements and Cementing

Cementing materials will have to be improved. High temperatures cause two serious problems with current cements: "flash" setting or hardening of the cement before it is totally in place and loss of most of its compressive strength. These problems are expected to be overcome.

Logging Tool Capability

Considerable progress will be required in logging technology to make proper monitoring of ultra-deep wells possible, particularly since logging time availability will become shorter, in the interest of maintaining an open well.

Optimized Drilling

The use of computer programs to make projections and completion schedules for drilling operations will continue to be developed. The programs and data banks will be developed and enlarged in the future, making the drilling of a given well as economical and efficient as possible.

However, each of these techniques and improvements will have to be tested in normal drilling operations under controlled conditions and eventually tested under ultra-deep drilling conditions.

Regardless of the advancements in techniques and equipment, the cost of ultra-deep drilling for geothermal energy sources must be competitive with other forms of energy

production. Although the cost of oil is increasing rapidly, it has not increased enough to make deep drilling for geothermals cost effective.

6.3 Areas for Further Research

It is recommended that research on alloys, bits, temperature and pressure effects, lasers, high-pressure jet drilling, and dual shafts be continued and that controlled testing be conducted in hard rock.

7.0 TASK 7: FURTHER RESEARCH AREAS WITH HIGH PAYOFF

Delineate and recommend areas in which further research effort could have high payoff.

7.1 Technical Approach

The project was reviewed and the research suggestions were indicated after each task was examined. From the discussions and suggestions, the research areas with the highest potential payoff were selected.

7.2 Findings

From the suggestions for research indicated at the conclusion of each task presentation, the following research areas are believed to have the highest payoff potential:

- Physical/mechanical conditions of rocks at ultra-deep levels should be examined in light of the research on high pressures carried out at the Geophysical Laboratory, Washington, and the universities of California and Gottingen.
- The containment of large-diameter cavities from pressures of 20,000-50,000 psi should be investigated further. The effort should include a compilation of strengths of different bulk materials, as well as means of underground emplacement and support.
- Novel high-energy techniques of rock removal–rock melting, electric arc drilling, laser drilling, and hydraulic drilling–should be assessed, primarily with regard to their potential use within existing drilling technology. Quantitative extensions of capabilities and economies should be sought.
- A preliminary research effort should examine the physical and chemical condition of the deep reservoir to determine how it can be modified and utilized. This research could have a high payoff in terms of geothermal utilization.

III. COMPARISON OF POWER COSTS FOR SEVERAL ENERGY SYSTEMS

This section provides some perspective on the estimated costs of hot, dry rock geothermal power and those of conventional and nuclear power plants. Precise economic comparisons are not possible because of the speculative nature of the geothermal energy cost estimates. A variety of sources were utilized to develop the composite comparison provided in Figure 14. The key sources were:

Geothermal Costs

a. Rex, R.W., "Table of Estimated Geothermal Reserves," cited in *Assessment of Geothermal Energy Resources*, Committee on Energy Research and Development Goals, Federal Council for Science and Technology, 1972.

b. Smith, M., *et al.*, "Induction and Growth of Fractures in Hot Rock," Chapter 14 in *Geothermal Energy*, edited by P. Kruger and C. Otte, Stanford University Press, 1973.

Nuclear and Conventional Energy Costs

a. International Atomic Energy Agency, *Market Survey for Nuclear Power in Developing Countries*, 1973. (Liberal use was made of capital costs, fuel costs, operating and maintenance costs, etc. contained in this excellent recent study centering on low- and medium-power system alternatives.)

b. National Petroleum Council, *U.S. Energy Outlook*, 1972.

Capital plant costs were converted to equivalent power costs (mils/kwh) based on a 15 percent return on investment, 25-yr (nuclear and conventional) or 20-yr (geothermal) system life, and 80 percent operating availability.

Cost figures are based on U.S. equipment and labor, are are presented in terms of constant 1973 dollars. Information on the sensitivity of these costs to the use of foreign equipment is available from the *Market Survey* but was not considered in this gross comparison. The *Market Survey* heavy fuel oil price of \$2.55/bbl delivered is, of course, no longer realistic because of the escalations during the current oil embargo and energy crisis. A figure

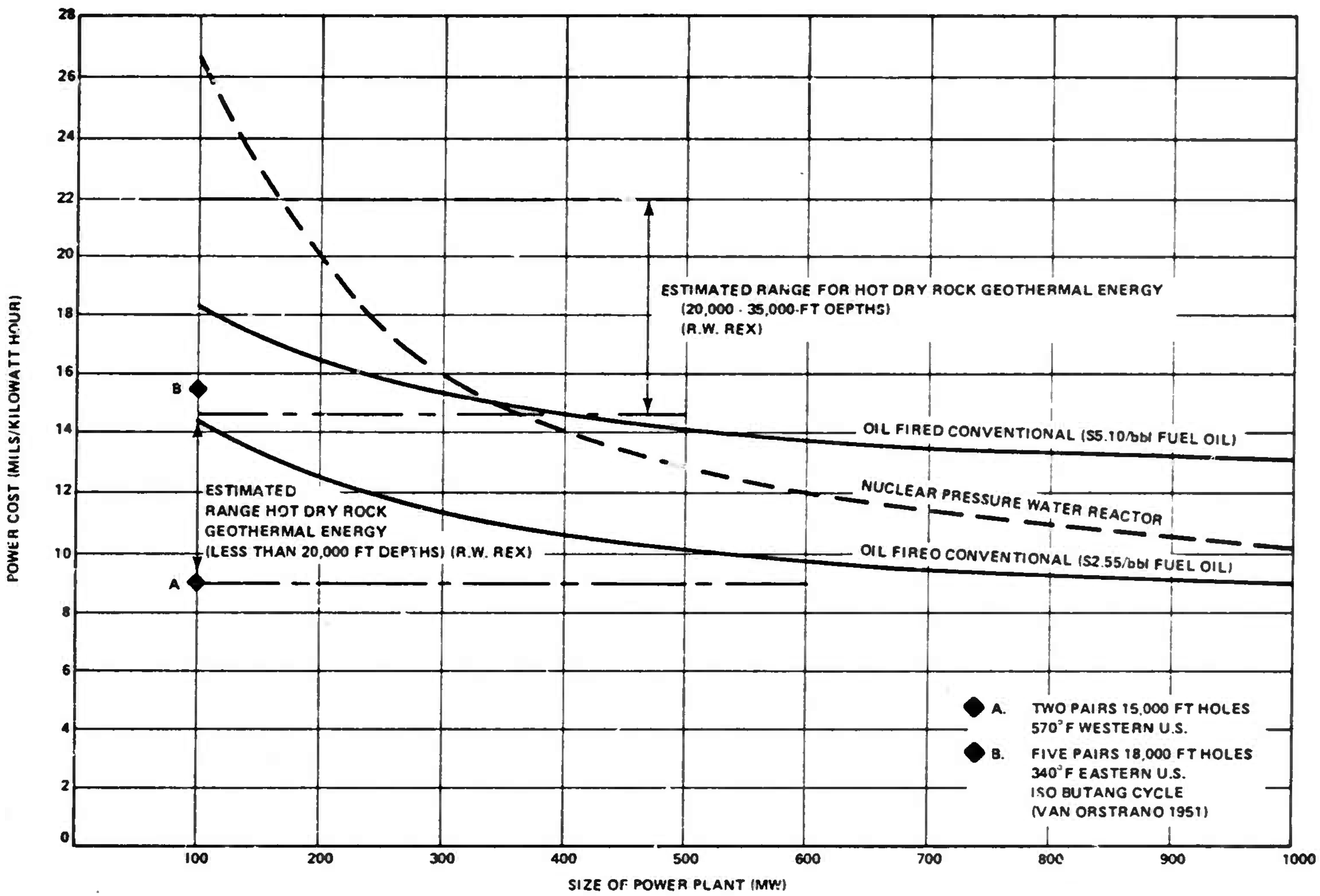


Figure 14. COMPARATIVE ESTIMATES OF POWER COSTS

of \$5.10/bbl is currently more accurate, and the cost could easily reach \$7/bbl before stabilizing. The graph in Figure 14 dramatically illustrates the impact of fossil fuel supply cost variations in this price range on the comparative costs of producing electrical power.

The two specific geothermal system cost estimates (points A and B in Figure 14) were drawn from the article by Morton Smith *et al.* These points fall (on the lower ends) in the general ranges estimated by R. W. Rex in Table 1.

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Appendix A

State of the Art of Geothermal Exploitation: Review of Research, Development and Operation

Excerpts from "Geothermal Energy," Vol. 12, Earth Sciences Series, UNESCO, 1973

(Updated and modified by inputs of the United Nations Geothermal Staff)

THE STRUCTURE AND BEHAVIOUR
OF GEOTHERMAL FIELDS
after
Giancarlo Facca
Consulting Geologist

1. INTRODUCTION

All geothermal fields differ, of course, from one another. Nevertheless certain common features have enabled rational theories to be advanced concerning their structure and behaviour. Gradually a clearer understanding is emerging from the immense volume of exploratory and research work that has been, and is being, undertaken in many parts of the world.

2. TYPES OF FIELD

A primitive classification of geothermal field types, regarded as mining enterprises, distinguishes three broad classes, as follows:

2.1 Hot Water Fields

Hot water fields, containing a water reservoir at temperatures ranging from 60 to 100°C. The thermal gradients in fields of this type may range from 'normal' (about 33°C/km), at which hot water of useful temperature would occur at depths from about 1,800 m to 3,000 m, to values of about twice the normal or more. Examples of the latter are the Hungarian Basin (50 to 70°C/km gradient) and the Arzag Basin in Southern France (60°C/km gradient), and many regions of the U.S.S.R.

2.2 Wet Steam Fields

Wet steam fields, containing a pressurised water reservoir at temperatures exceeding 100°C. This is the commonest type of economically exploitable geothermal field. Notable examples under exploitation are Wairakei (New Zealand), Cerro Prieto (Mexico), Reykjavik area (Iceland), the Salton Sea (U.S.A.) and Otake (Japan). The hottest known field is Cerro Prieto (380°C).

When hot water is brought up a well to the surface, and its pressure is sufficiently reduced, some of the water will be flashed into steam. The proportions of water and steam vary from field to field, and from well to well in a single field, according to the enthalpy of the fluid at depth and the pressure at the wellhead. Such fields can be suitable for power generation.

2.3 Dry Steam Fields

Dry steam fields, or those that yield dry or superheated steam at the wellhead, at pressures above atmospheric. Degree of superheat may vary from 0 to 50°C. Examples of this type of field under exploitation are Larderello and Monte Amiata (Italy), The Geysers (California) and Matsukawa (Japan). This type of field is also suitable for power generation.

Geologically, wet steam and dry steam fields are generally similar, as emphasised by the fact that in some cases wells have produced wet steam for a period and dry steam later.

3. BASIC MODEL OF A GEOTHERMAL STEAM FIELD

The basic features of a geothermal steam field, wet or dry, are:

(i) a source of natural heat of great output

(ii) an adequate water supply

(iii) an 'aquifer,' or permeable reservoir rock

(iv) a cap rock

There is general agreement that the source of heat is a magmatic intrusion into the earth's crust, having a temperature of 600 to 900°C, often at depths of the order of 7 to 15 km. This view is supported by various facts and reasons, notably that all the known

'commercial' fields are in regions where volcanic activity has occurred during recent Miocene–Quaternary times, or is still occurring. Some fields are actually situated on, or close to volcanoes (e.g., Japan and Central Mexico), whereas others (e.g., Larderello) are not directly linked with a centre of recent volcanic activity. Steam fields thus appear to be located in areas either of active, or of dormant (cryptovolcanic), activity.

In an active volcano, a magmatic intrusion reaches the surface through a large fault system. In compact, hard rock faulting may provide a channel for the upward flow of magma, while plastic rocks such as clay may flow by gravity into the fault space and seal it from above. The energy of a magmatic intrusion may be sufficient to penetrate the fault system in hard rocks but insufficient to prevail against the overburden of the plastic rocks. In such cases the magma may intrude to the boundary between the hard and plastic rocks. This cryptovolcanism may occur in areas devoid of recent volcanic activity, and is more likely to be found in geological areas of thick plastic formations, like a turbiditic series (flysch, greywacke). This applies to the two major dry steam fields, Larderello and the Geysers.

Magmatic intrusions without present eruption are common in acidic volcanoes and can also occur in basic volcanoes. Such intrusions provide the heat source for the Japanese and Central Mexican fields located on or around volcanoes.

In petroleum exploration it is recognised that the necessary geological environment for an accumulation of oil is a sedimentary basin. The existence of such a basin, of whatever age, may offer the lithological and structural conditions that can equally be regarded as promising signs of the existence of a magmatic intrusion?

Two such environments are as follows:

(a) *Rift valleys and large grabens.* The large structural depressions of the earth appear to be caused by the splitting apart of the crust at rates of several centimetres per year. The best known of these depressions is The Great East African Rift Valley, which passes from Tanzania through Danakil, The Red Sea, Jordan Valley, into Lebanon and Syria. It is the site of Quaternary to active volcanism. Surface thermal activity is common in this valley but there could be good geothermal prospects in places where there is less obvious evidence of abnormal heat flow. Another area of this class passes through the Gulf of California and the Salton Sea, in North America. The Basin and Range geological province in the Western U.S.A. is another such region; the basins are grabens.

There are good reasons for believing that grabens are the preferred site of magmatic intrusions.

(b) *Turbidites areas.* Larderello, Monte Amiata and The Geysers geothermal fields are all located in a turbidite geological environment. Preliminary exploration has been carried out in one such region, the Flysch province of North-East Algeria.

3.1 Water Supply

It is now believed that at least 90% of the water in a geothermal reservoir is 'meteoric,' originating from rain water.

As hot fluid is withdrawn from bores or from surface vents, the hydrological balance of the system is restored, or partially restored, by the inflow of new water. Our knowledge of water movements in deep aquifers is very limited.

3.2 The Aquifer

A good productive geothermal well should produce at least 20 t/h of steam: many wells produce a great deal more. A 'wet' well may produce some hundreds of tons per hour of mixed fluid. The maintenance of such high flow rates implies a high degree of permeability in the aquifer, with porosity playing only a secondary part. Any permeable rock can serve as a good geothermal reservoir. At the Geysers it is greywacke with fissure permeability; at Larderello a carbonate rock with karstic permeability; at Wairakei, fissured ignimbrite overlain with rhyolite and pumice breccia; at Otake, a permeable volcanic tuff; at Cerro Prieto, deltaic sands.

3.3 Cap Rock

A cap rock is a layer or rock of low permeability overlaying the aquifer. All steam producing fields have a cap rock. Some have been formed as original impervious rocks, such as the flysch formation at Larderello, the lacustrine Huka formation at Wairakei, the deltaic clay in the Imperial Valley and Cerro Prieto fields. Elsewhere, the cap rock may have become impervious as a direct result of thermal activity.

4. THE GEYSERS GEOTHERMAL FIELD, CALIFORNIA

The Geysers steam field is located in the Coast Range geological province of California, about 140 km north of San Francisco. It is one of the few dry steam fields now being exploited. With an impressive record of successful drilling (70 producing wells in 1970, in a total of 75 drilled) the field is still under development. Several additional bores are being

sunk every year and the boundaries of the field have not yet been reached. The field would appear to be the largest in the world. Steam equivalent to about 400 MW of power has already been proven; while the potential of the drilled area, which covers at least 20 sq. miles, has been conservatively estimated at 1,300 MW. There are reasons for believing that the exploitation of the whole thermal area could produce at least 3 or 4 million kw.

4.1 Geology

Widespread young volcanic activity is an outstanding geological feature of the region. At the centre of the field the Cobb Mountain is a rhyolitic dome. At the present eastern end of the field, in the Middletown area, there are very young volcanic vents, lava flows and tuffs. Northwards there are Mounts Hanna and Konocti which are very recent volcanic domes.

The reservoir is provided by the Franciscan greywackes. Although the primary permeability of greywacke is almost nil, intensive fracturing provides high secondary permeability. When drilling, circulation losses are common, especially below 3,000 ft. The reservoir appears to be very thick, certainly over several thousand feet and possibly more than 10,000 ft. This could provide ideal conditions for deep seated fluid convection.

At shallow depth there is a layer of impervious rock, as proven by air drilling. Much of this rock appears to be an example of the self-sealing process.

In the early days of exploration in the Geysers field, the theory was commonly held that the origin of the steam was magnetic. However, intensive drilling has shown that many good steam producing wells have been sunk in areas where no faults have been detected. These facts have led to a modified theory that either none or only a small proportion of the total field steam (less than 10% according to isotope tests) originates in the magma.

The steam reservoir extends to a great depth, well below the deepest bore, and is believed to be heated mainly by conduction through bedrock from a magma intrusion beneath. The upper part of the reservoir, after many years of production, is now filled with steam and gases, while deeper down it is believed to contain boiling water.

5. THE OTAKE GEOTHERMAL FIELD, JAPAN

The Otake field is located in Kyushu Island, a few kilometres northwest of Mount Kujyu-Zan. A 13 MW power plant was commissioned in 1967 and has since been operating

at high plant factor. It is planned to develop the area to the extent of about 180 MW.

The Otake field lies in a faulted caldera basin surrounded by volcanoes. Numerous hot springs and fumaroles located along the major faults in the basin indicate abnormally high heat flow.

Volcanic activity began in the Miocene age and continued until the Holocene. Fracturing and fissuring occurred, imparting secondary permeability to the rocks. Meanwhile, the surrounding volcanoes became active again and covered the area with the lavas and tuff breccias, thus providing a cap rock over the convective system, the temperature of which consequently rose. Hot fluids, previously confined in the convection system, migrated to the surface through active faults.

6. THE LARDERELLO GEOTHERMAL FIELD, ITALY

This field, occurring in Tuscany about 50 km south of Pisa, is at present being exploited to a greater extent than any other geothermal field in the world. About 390 MW of power plant is generating about 3 million kWh per annum. The field yields superheated steam, sometimes reaching 260°C. Typical conditions are 5 ata/225°C at the wellhead; maximum enthalpy 705 kcal/kg.

6.1 Geology

The field lies in the southern part of the Era graben. The limestones of the main reservoir have very high karstic and fissure permeability. The reservoir thickness varies, sometimes reaching several hundreds of metres.

6.2 Tentative Explanation of Field Behaviour

It is suggested that before steam production began, the reservoir was filled with liquid water near boiling point. When fluid was drawn off from a well penetrating a reservoir dome, an 'evaporation space' would be formed. In the course of time the evaporation spaces of the shallower wells would have become enlarged until they merged into one another. All wells would then produce steam only. The steam/water interface is believed to have fallen continuously owing to the insufficiency of recharge water to make good the steam draw-off.

DRILLING FOR GEOTHERMAL STEAM AND HOT WATER

after

Keiji Matsuo
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1. INTRODUCTION

Geothermal steam is sometimes found at depths as shallow as 50 m to 200 m, but the output from such sources is often impermanent, and the steam used for power or industrial purposes is usually found by drilling to depths of 300 m to 2,000 m. Exploration for geothermal steam sometimes necessitates drilling as deep as 2,500 m to 3,000 m.

Geothermal wells are generally drilled with standard rotary rigs as used for crude oil and natural gas. In some respects, however, drilling for steam differs considerably from that for oil and gas.

2. METHOD OF DRILLING

The method used is the usual rotary drilling, either with mud or with air. The former is the most commonly used but the latter, being faster and cheaper, has attracted increasing attention in recent years.

3. DRILLING METHOD WITH MUD CIRCULATION

3.1 Drilling Proeess

Ground formations in geothermal areas consist mostly of volcanic rocks, characterised by a high hardness index, a high temperature gradient and strong faulting and fissuring. Losses of circulating fluid are therefore frequent and progress may be much slower than when drilling for oil or natural gas.

The time required for drilling is greatly influenced by the topography at the site, the ease of access, the hardness of the formations, the efficiency of the rig, the amount of casing required, the lengths to be cored and the number of metres to be drilled in the productive zone where mud losses are high. Under favourable conditions the following times are reasonable estimates:

Depth	Actual Drilling	Finishing & Testing
500 m	15 to 30 days	10 days
1,000 m	25 to 45 days	10 days
1,500 m	35 to 55 days	10 days
2,000 m	50 to 70 days	10 days

3.2 Casing Programme for Steam Produetion Wells

An important item in the planning of a steam production well is a proper casing programme. A large volume of steam production should be expected as a matter of course from a large diameter well. But if a well is too large for the capacity of the steam formation, it will not always produce abundant steam and is more likely to be incapable of maintaining a sustained flow.

Further problems arise from the pH values of the hot water produced with the steam.

In some cases slotted liners can be used, but it is best to avoid them unless there is a risk of the hole walls collapsing during the long period of steam production.

The casing programme will also differ according to the volume of hot water produced with the steam. As a general rule it will conform with the following classification:

(a) Steam volume 10 to 25 t/h:

17-in open hole	13-3/8 in surface casing	fully cemented
12¼-in open hole	9-5/8 in intermed: casing	fully cemented
8-5/8-in open hole	7 in production casing	fully cemented
6¼-in open hole	4½ in slotted liner	

(b) Steam volume 25 to 50 t/h:

18-in open hole	16 in surface casing	fully cemented
14¾-in open hole	11¾ in intermed: casing	fully cemented
10-5/8-in open hole	8-5/8 in production casing	fully cemented
7-5/8-in open hole	6-5/8 in slotted liner (O.D. of coupling skimmed by 1/16 in)	

(c) Steam volume 50 to 80 t/h:

22-in open hole	18 in surface casing	fully cemented
17-in open hole	13-3/8 in intermed: casing	fully cemented
12¼-in open hole	9-5/8 in production casing	fully cemented
8-5/8-in open hole	7 in slotted liner	

3.3 Casing

Casing to be used for the production of large volumes of steam from subterranean formations must be able to withstand vibration, attrition through friction, wear and corrosion so as to remain in service for as long as possible. To minimise the attrition of the slotted liner it must be as large as possible by comparison with the hole diameter. For instance, in an oil well a 5½-in casing is inserted into an open hole of 7 5/8-in diameter; whilst in a geothermal well a 6 5/8-in casing (with the outside diameter of the coupling skimmed by 1/16-in) will be used in a hole of the same diameter. This is to ensure a minimum clearance between the outside of the casing and the walls of the hole. The sectional area of the 6 5/8-in casing is 40% greater than that of the 5½-in casing.

As regards the wear of the casing, steam produced at a rate of 70 t/h passing through an 8 5/8-in CP nearly reaches sonic speed, which severely damages the casing.

The steam can come out superheated, dry saturated or wet. Steam with a wetness of 20 to 30% or more is the most damaging. A film of water, some 0.03 in thick, appears to cover the inside walls of the casing. Severe damage is caused when this film is removed by high speed steam.

J55 steel to A.P.I. standards is generally used in most countries for the manufacture of casings, but for cases of serious corrosion it is essential to use an acid-proof casing capable of resisting hot, highly acid geothermal waters.

All piping at the wellhead above the main valve must be streamlined and the wall thicknesses increased to resist corrosion and wear.

3.4 Drilling Mud

At comparatively low temperatures, around 150°C, drilling of geothermal wells is usually carried out with bentonite or other clay-based muds. Above this temperature the mud tends to 'gel' and the filtrate to increase. CL-CLS based mud is therefore generally used with satisfactory results.

CL-CLS denotes chrome-lignite/chrome lignosulphonate. This type of mud is very effective in formations which easily cave in, and when cement contamination is pronounced. It is stable at high temperatures and can withstand up to 250°C.

As the drilling mud is submitted to high temperatures within the hole, it is necessary to cool it. A cooling tower must therefore be installed. The difference in temperature before and after showering is 10 to 15°C. This can be extended to 20 to 25°C by installing a fan.

3.5 Prevention of Circulation Losses

This is of primary importance when drilling a geothermal well, and the counter-measures taken can be permanent or temporary. The permanent measure is to seal off the level at which losses occur, by cementing.

Temporary measures consist of plugging the formations with nutshell powder, sawdust, cotton seeds, celophane, fibre scrap, etc. These vegetable materials are carbonised in the course of time once the well has been completed, and the steam production capacity of the formation is restored.

3.6 Cementing

When cementing a geothermal steam well, the most important factor is that the cement slurry should rise uniformly and continuously from the casing shoe to the ground level. For this to be achieved, the filter cakes of the drilling mud should never be thick, even at high temperature. Also sufficient clearance must be assured between the casing and the wall of the hole for the void to be uniformly filled with cement. The casing must therefore be correctly centred by the use of centralisers. If the mud cake is too thick, it may be necessary to use 'scratchers.'

The cement slurry should be prepared in sufficient quantity, generally 1.5 to 1.7 times the estimated amount required, and injected by a large capacity pump which will prevent it channelling.

3.7 Cement

Ordinary Portland cement is adequate for geothermal steam wells up to temperatures of 150°C, but is insufficient above that. In general, the strength of hardened cement decreases, and its brittleness and permeability increase with time, if the temperature during the period of hardening rises above 120°C. This can be prevented by mixing with silica flour. Cement to A.P.I. standards is classified into eight categories from 'A' to 'H'. These are used in oil wells according to depth, temperature, pressure, sulphate resistance, etc. For use in geothermal steam wells these cements must be supplemented with 30 to 50% of silica flour to reduce brittleness and permeability when hardening.

A method of decreasing the specific gravity and improving the adiabatic properties of cement is to mix perlite with the slurry. In countries where silica flour is not readily available, fly ash from thermal power plants can be used instead. Fly ash contains 55 to 60% silica, and a mix of 50% Portland cement with 50% fly ash (pozzolana) is used at a 50% water/solid ratio.

3.8 Directional Drilling

Well spacing for geothermal wells of 500 m to 2,000 m depth is usually 100 to 300 m.

The direction and angle of a hole cannot be measured at high temperature. The hole

must therefore be diverted at shallow depth when the temperature does not constitute an impediment. In hard formations turbo drill equipment is used as a deflecting tool.

3.9 Drilling Failures

Particular failures which may occur while drilling geothermal wells are as follows:

- sticking of the drilling column because of gas blow-outs
- sticking of the drilling column because of rapid loss of mud circulation
- parting off of the tool joint on the drilling column when drilling at high temperature in the winter season
- breaking off of the threaded section on the drill collar, when encountering hard formations, etc.

Failures upon completion of a well can be due to:

- pressure collapse of the production casing due to rapid temperature rises in water pockets possibly trapped in the cement between the intermediate and production casings, due to heating by the steam flow
- parting off the casing couplings when the outside of the production casing is inadequately cemented
- rupturing of the casing below the main valve at the wellhead by large quantities of rock and dust carried up by the steam

3.10 Counter-Measures Against Drilling Failures

Prevention of steam and gas gushes. The reservoir formations of steam and hot water must always be cooled whilst drilling so that their temperature does not rise above boiling point. When the temperature of the circulating mud is abnormally high, the mud should be passed through a cooling tower. Particular attention must be paid, especially at shallow depths, to excessive temperature rises due to hot steam entering the hole through fissures in the steam formation. Once a steam blow-out has occurred, the preventers at the head of the rig must be closed. But if the casing carrying the preventers is not well grouted in a competent formation, or if the cementing is inadequate, steam may then begin to flow outside the casing and around the rig.

The formation holding the casing which carries the preventers must therefore be carefully selected, and cementing must be carried out perfectly.

Once the preventers have been closed, the steam blowing formation must be cooled by pumping cold water into the well.

Steam blow-outs can also occur whilst raising the drill-pipe, because of inadequate cooling of the mud or insufficiency of mud, or because of swabbing action caused by thick mud and clogged drill strings, especially near the collar. It is therefore essential to use good quality mud capable of withstanding high temperatures. Trouble can also be avoided if the drill strings are provided with a back valve or kelly cock. Without these, even if the preventers are closed, steam can rise through the drill-pipe and rotary hose, and the latter will be split by the heat and pressure, thus causing a blow-out and damage.

Preventing the drill-pipe from sticking through rapid circulation losses. When drilling in the productive zone, circulation losses are desirable because they indicate the presence of steam layers and are a guide to the productibility of the formation. The more pronounced the circulation losses, the quicker will the mud tend to settle downwards, carrying with it washings off the wall of the hole. The drill-pipe must therefore be raised as soon as possible, or else it will be liable to stick.

Recovery of a stuck drill-pipe. A stuck drill-pipe may be recovered as follows:

(a) by immersion in lubricating oil

(b) by using bumper and rotary jars

(c) by using back-off tools (provided the temperature in the drill-pipe can be maintained at 90°C for around 30 minutes after cooling)

(d) reaming out the stuck drill-pipe

Parting off of a drill pipe joint. When a high temperature well is drilled in winter, the pipe joints expand under the high temperature. When cold water is fed into the drill-pipe, the male screw section of the joint is liable to shrink and to part from the drill pipe.

Break-off of the drill collar. This can occur when drilling with a heavy bit load and slow penetration in hard formation. The thread of the drill collar is repeatedly subjected to strong shocks when drilling in hard formation and is liable to fatigue through chattering.

Collapse of production casing due to water pockets. This may lead to a collapse of the production casing at depths above that at which the intermediate casing has been put down. The only means of recovering a collapsed production casing is to ream out the cement around the production casing with a well connected pipe of suitable size from the cellar of the hole, to screw a large left-hand casing tap into the head of the production casing at the reamed out section, to fish out the damaged casing step by step, and finally to screw a new casing into the lower joint in place of the damaged casing.

Parted coupling on the production casing. This may occur because of frequent temperature changes, especially if the outside of the casing is not properly cemented in.

Rupture of casing below the main valve at the wellhead due to abrasion by rock dust. When a well has been completed and begins to blow steam, a large amount of rock dust can sometimes be carried by the steam for many hours. This can have a sandblasting action and wear through the steel pipe at the wellhead. Such an aperture grows rapidly and must be closed as soon as possible. (Example of success: Matsukawa, Japan).

4. AIR DRILLING

Ordinary drilling is by the rotary method with circulation mud; air drilling is rotary with circulating air instead of mud. This method has been tested over several years in various countries. Particularly good results have been achieved at the Geysers, California.

Particular features of this method of drilling are:

(i) high drilling speeds and low drilling costs (speeds 3 to 4 times greater, but life 2 to 4 times longer, than with mud drilling)

(ii) no damage to the production zone from circulating mud injected during drilling

Air drilling has, however, certain disadvantages, and is unsuitable for formations bearing excessive water or with a strong tendency to slough. Mud drilling must then be used.

It is the usual practice first to drill the formation with mud and then to resort to air drilling, or to drill with air in the production zone once the production casing has been put down and cemented in.

In many cases, once the production zone has been drilled, the hole is completed without inserting a slotted liner. If a liner is required, the hole is first cooled with water, which is then replaced with mud, and the slotted liner is inserted. The same practice is followed when the production casing is inserted and cemented after air drilling.

4.1 Mechanical Equipment (Attachments to the Rotary Drilling Rig)

Primary and booster compressors. In air drilling, an air compressor and booster compressor replace the pump used for rotary drilling with mud. The primary compressor must

provide an air velocity of 2,000 to 5,000 ft/min in the annular section between the hole and the drill-pipe. The pressure will depend on the drilling depth foreseen. The capacities of the primary and booster compressors at the Geysers, California, for depths of 1,500 to 2,000 m were respectively:

700 ft^3/min x 300 psi x 5 units (one spare)
1,500 ft^3/min x 1,200 psi x 2 units

Rotary drilling head (rotary Kelly packer). This is a preventer attached to the top of the double gate blow-out preventer. If water cooled, it can be used up to temperature of 250°C.

4.2 Counter-Measures for Water Intrusion

As water intrusion from the formation increases, the efficiency of air drilling drops, and it may ultimately become necessary to resort to classical drilling.

4.3 Other Obstructions and Remedies

Cementing test. As water seepage into the well constitutes a serious impediment to air drilling, water leakage through the cemented casings must be carefully watched for.

Crooked hole. In air drilling, the line of pipes is not supported by surrounding mud, and bit reactions are strong. The bit therefore tends to deviate and the hole to lose its alignment. To maintain a straight hole, large diameter collars are used behind the bit.

5. WELL SURVEYS

A well must be surveyed during and after drilling. The suggested survey is set out in Table 2.

Table 2. WELL SURVEY

Investigation Item	Surveying Instrument	Purpose of Investigation
Temperature measurement	Point survey: (thermometer, geothermograph). Multiple survey (Kuster); continuous survey (thermistor).	Study of the change of temperature of the well, distribution and condition of geothermal heat. Presumption of steam and hot water layers.
Electrical log		Geophysical determination of formations.
Flow measurement	Spinner.	Flow measurement of steam of geothermal water at required depth.
Inclination measurement	Totoko and Murata type.	Measurement of direction and inclination of borehole, and charting the position and tract of the well.
Pressure measurement	Amerada (bourbon tube). Humble type (spring).	Measurement of the pressure in the well, and presumption of the production capacity.
Collection of bottom hole sample	Bottom hole sampler.	Collection of geothermal fluid sample at required depth.
Cement bond log	Application of sonic log.	Investigation of cementing work.

6. WELL SPACING

In many countries experience has led to an empirical well spacing of 100 to 300 m for depths of 500 to 2,000 m.

7. SAFETY INSTALLATION AND PRECAUTIONS

Steam gushing during drilling operations takes a long time to control by means of the preventer, owing to the high temperature. Water supply must be sufficient for a possible emergency.

Periodical checks should be carried out and all crew members trained in the operation of preventers without loss of time.

The blow-out preventer is carried by the casing. The space around the casing must therefore be perfectly sealed off with cement to avoid steam gushing out when the preventers are closed. The casing shoe must be firmly held in a competent formation and any void outside the casing must be completely and uniformly filled with cement.

The gas emitted by a well may contain highly poisonous hydrogen and arsenic sulphides which can produce giddiness and eye injury even in low concentrations. Gas masks and detectors must therefore always be kept ready.

When steam and hot water start to gush while drilling is in progress, men working on the derrick may be unable to reach the ladder. An escape cable carrying a 'bosun's chair' or any other man-carrying appliance must therefore be provided.

THE UTILISATION OF

GEOTHERMAL FLUIDS

A-19

GEOTHERMAL POWER
after
Basil Wood
Consulting Engineer

1. POWER PLANTS INSTALLED

Table 1 contains a list of major geothermal plants in operation or in construction. In a few places, e.g., Salton Sea and others (not included), a geothermal plant has been installed but has fallen into disuse.

Table 1. GEOTHERMAL POWER STATIONS

Plant	Country	Date	Total installed MW	Largest unit MW
Larderello	Italy	1930-1969	330	26
Wairakei	New Zealand	1958-1963	198	30
Kawerau	New Zealand	1961	10	6
The Geysers	California	1960-1971	192[1]	55
Salton Sea	California	1966	3	1.5
Pauzhetka	Kamchatka	1967	5	2.5
Paratunka	U.S.S.R.	1970	0.5 (Freon)	0.5
Matsukawa	Japan	1966	20	20
Otake	Japan	1967	11	11
Pathe	Mexico	1958	3.5	3.5
Mexicali	Mexico	1972?	75	37.5
Akureyri	Iceland	1969	2.5	2.5

[1]Plus 220 more visualized.

There are two types of geothermal field, namely those yielding dry steam (Larderello and the Geysers) and those yielding wet steam—a mixture of boiling water and flash steam as at Wairakei, Mexicali, Iceland, and El Salvador. As a rough rule 1% of the water will flash into steam for every 10°F reduction in saturation temperature. In practice the proportion of steam to water obtained in various fields is 1:4 to 1:10, the steam being separated from the water in cyclone separators ordinarily at the wellhead. The 'dry' steam at Larderello and the Geysers may by throttling acquire a few degrees of superheat but the expansion through the turbine is effectively entirely in the wet region.

The wide application of wet steam in American nuclear plants has greatly stimulated interest in the subject and influenced both attitudes and equipment available. In nuclear engineering, because of heavy subsidies and deliberate under-estimating of costs, very expensive techniques have been employed such as resorting to stainless steel on every occasion. Geothermal engineers, being confined to much more moderate budgets, have been obliged to find cheaper solutions.

2. BASIS OF SELECTION OF MATERIALS FOR GEOTHERMAL SCHEMES

So far only about 4 manufacturers have experience of geothermal turbines. Others have in the main shied away from the difficulties which their metallurgists, probably on the basis of hasty tests or judgment, tended to exaggerate. It appears that there is now a risk of a swing in the other direction with new manufacturers and ideas based on nuclear designs coming in with possibly erroneous notions on corrosion based on misunderstanding of published data or an excess of confidence derived from insufficient background knowledge.

3. TYPES OF TURBINES EMPLOYED

The various possibilities are illustrated in Figure 1. The simplest process, applicable only where steam is available at above atmospheric pressure, is to put it through a turbine exhausting to atmosphere. This is wasteful in that the heat drop available below atmospheric pressure is ignored, but may have to be done if the gas content of the steam is too high to permit an economical working under vacuum. Such a plant up to 5 MW can be semi-portable, might be obtained quickly, and can be installed on temporary foundations.

4. CONDENSING TURBINES

In all larger geothermal plants the raw steam is put through condensing turbines (Fig. 1 (2) (3) (4) (6))–a large fraction of the output–say ½ to 2/3 being developed below atmospheric pressure.

Condensing steam plant is more elaborate than that with atmospheric exhaust, needs more skilled attention, and involves more permanent structures, consideration of levels, and provision of circulating water and auxiliary plant.

5. INDIRECT SYSTEM

In the early plant at Larderello the indirect system was adopted whereby the raw steam was taken through a heat exchanger and caused to re-boil its own condensate to yield pure steam at a lower pressure, the feed to the secondary (open) circuit being the (degassed) primary condensate. Thus (feared) corrosion from H_2S and CO_2 was avoided in the turbine though in some degree it was transferred to the heat exchanger.

6. SELECTION OF PRESSURE AT TURBINES

The pressure at which the steam is to be utilised at the turbine depends in the first place on the pressure available at the wells. The highest pressure so far employed is 180 lb/in^2 at Wairakei with multi-cylinder turbines. Many fields do not permit of the selection of so high a pressure, 100 lb/in^2 being more usual. A further complication in selection of pressure is that wells may be of two classes markedly differing in pressure either due to depth or other cause. To make proper use of both classes may thus demand two steam pipe systems operating at different pressure.

7. ROUGH ESTIMATE OF STEAM RATE

In order to reach an idea of what output can be obtained from a given flow of saturated steam at a particular pressure, we require only the rough rule that each 1°F drop of temperature available results in a yield of 1 BTJ/lb (Wood's rule). The accuracy is ±10%,

which is something like the order of variation between turbines from the smallest to the largest sizes. There is nothing as simple as this rule applicable to superheated steam technology. For instance if steam is available at 100 lb/in^2 g (saturation temperature 338°F) and is exhausted to atmosphere (nominal temperature 212°F), the usable drop is about 126 BTU/lb. Since 3,412 BTU = 1 kWh, 1 BTU/sec = approximately 1 kW. Therefore 1 lb/sec of steam will yield approximately 126 kW.

8. LIMITS ON UNIT SIZE

The largest units operating are at Wairakei 'B' station being single-flow 30 MW machines running at 1,500 rpm with an inlet pressure of 50 lb/in^2 and back pressure of 1½-in Hg. Their record has been substantially trouble-free. Several 50 MW two-flow 3,600 rpm machines are on order for the Geysers station to operate at 100 lb/in^2 and 4-in Hg back pressure (55 MW overload rating).

9. COOLING WATER

The required quantity of circulating water is arrived at by a rough rule that the latent heat of the steam at the condenser is of the order of 1,000 BTU/lb. Hence every pound of steam to be condensed requires 50 lb of water with a temperature rise in the condenser of 20°F (or pro rata). Where a more accurate calculating of cooling water requirement is called for, it is necessary to know the heat consumption of the turbine. If for instance the performance is quoted as 15 lb/kWh of saturated steam at 150 lb/in^2 gauge and 2.5 in Hg abs back pressure, then since the heat content of such steam is 1,196.8 BTU/lb and the condensate contains 76.6 BTU/lb, the heat rate is 15 x 1,120 = 16,800 BTU/kWh.

While a source of natural cooling water is as advantageous for geothermal stations as for orthodox stations (for instance a sizeable river, lake, or sea), a geothermal plant is unique in providing its own make up for cooling towers automatically.

10. CONSIDERATION OF ALTERNATIVE FLUIDS TO STEAM

10.1 Supercritical Use of a Refrigerant (R12)

The high yield in Fig. 6 of 61.4 BTU/lb at 380°F shown by R12 ($C\,Cl_2F_2$) is attained by using it above its critical temperature of 234°F and critical pressure of 597/lb/in² abs choosing initial conditions of 1,800 lb/in² 380°F to produce just dry state at end of expansion to 100°F. Heat exchange with the water is facilitated by the heat intake line in the supercritical compressed fluid being likely to be not far from straight (no published data). A 'nip' temperature difference of about 40°F is assumed. The heat intake is 75 BTU/lb of R12 and the isentropic heat drop some 18.7 BTU/lb. The feed pump however at 100% efficiency takes 3.9 BTU/lb leaving 14.8 nett on isentropics. However if we allow for a practical pump efficiency of 70% including motor with 25% pressure drop, the feed pump power deduction rises to 7 BTU/lb. The turbo-alternator might show 85% efficiency, yielding 15.9 BTU/lb and the net output is thus 8.9 BTU/lb. The exchange ratio is approximately 4.1 lb of R12/lb of water. Hence there is the prospect of coming out with a practical 36.9 BTY/lb of water. This is however no better than obtainable by double flash (37.5).

The capital cost of supercritical R12 plant is likely to be high in view of the high working pressure for which the heat exchanger (1,800 lb/in²) and the condenser (130 lb/in²) have to be designed. The Russian plan referred to earlier seems to represent a full scale experiment in the use of this refrigerant.

10.2 General Assessment

To summarise, it appears that the claims which are often made that some other fluid than water is more suitable for generating power in the low pressure region, do not seem to be proven. While it is conceded that theoretically a refrigerant can promise more output than does water in the single flash process, it appears that double flash can about match anything that refrigerants can hope to attain and is eminently more practical. Clearly where the heat is available in the form of steam or boiling water initially, there is the great virtue of simplicity in utilising the steam directly or deriving steam by the flashing process. In all cases so far investigated it seems likely to be cheaper to do this than to exchange heat into another fluid. We have, however, reliable cost data only for steam and until the exponents of some other fluid publish their figures we remain without actual cost data for the alternative.

One possible advantage of a refrigerant is the ability to provide independent start-up which is not obtainable readily with sub-atmospheric steam though it might be done in some cases by throttling a well to give higher pressure steam or boiling water for the ejectors. Against this may be set the inability of a refrigerant turbine to provide its own pure make up for the water cooling circuit thus attaining self-sufficiency in that direction. Moreover many other types of plant, e.g., gas turbines, diesels, and modern steam plant, are also incapable of a 'black start' except by reliance on some form of stored energy; indeed geothermal plant and hydro are almost unique in offering independent start-up.

Favourable conditions for a refrigerant are:

(a) Where the steam contains a high content (say 10%) of incondensible gases. If a secondary cycle is required for steam, then it has no initial advantage over another fluid.

(b) Where, as in the U.S.S.R., the vacuum temperature in winter might be so low that freezing risks occur with water and because of the very high specific volume, the annulus area required with steam becomes inconveniently large.

In the beginning it was somewhat difficult to persuade manufacturers that power from geothermal steam was a sound proposition even though the steam was not very different from that which they were familiar with in existing steam turbines. One can only suppose that there would be even more difficulty in persuading manufacturers and others of the value of developing a peculiar turbine to utilise a refrigerant, particularly as there is a great variety of refrigerants. The turbine design would be quite different from that of steam turbines and there would be no assurance that a development project would lead to continuing business, however interesting academically.

CORROSION CONTROL IN GEOTHERMAL SYSTEMS
after
T. Marshall and
W. R. Braithwaite

1. INTRODUCTION

The natural geothermal steam and high-temperature water found in volcanic areas are characteristically contaminated with chemical impurities of underground origin, and during their utilization they may be further co. taminated with impurities from the atmosphere. These impurities introduce corrosion problems which must be controlled in the design and operation of geothermal plants, furthermore the release of these impurities to the surface environment may introduce associated atmospheric and surface water corrosion problems.

The most common impurities encountered in geothermal fluids are:

Silica	Sodium
Chloride	Potassium
Fluoride	Lithium
Borate	Calcium
Sulphate	Magnesium
Carbonate	Ammonium

Hydrogen sulphide
Carbon dioxide
Hydrogen chloride

Of these, the non-gaseous impurities are usually removed by separation and/or scrubbing in the water phase before utilization of the steam phase in power generation. The gaseous impurities remain substantially in the steam phase. After utilization and/or condensation of the steam the gaseous impurities become concentrated, contaminated with atmospheric oxygen, and may be released to the atmosphere.

Thus the non-gaseous impurities are usually of major significance in water-phase corrosion in geothermal systems, while the gaseous impurities are usually of major significance in steam-phase, condensate and atmospheric corrosion.

The many possible interactions between these chemical factors, physical factors such as temperature and stress, and the various materials of construction present the main problems of corrosion control in the design and operation of systems for the utilization of geothermal fluids.

2. CORROSION PHENOMENA ENCOUNTERED IN GEOTHERMAL SYSTEMS

2.1 Surface Corrosion

Surface corrosion may be extremely severe in geothermal fluids containing free hydrochloric, sulphuric or hydrofluoric acid prohibiting the practical use of such fluids. Luckily surface corrosion rates of common structural materials are sufficiently low to permit their practical use.

2.2 Erosion-Corrosion

The conjoint action of erosion and corrosion (so-called erosion-corrosion) on metals is significant in some items of geothermal plant. Erosion-corrosion of turbine blades by wet steam at high velocity is particularly important in affecting the design and efficiency of steam turbines.

2.3 Stress Corrosion and Sulphide Stress Cracking

(a) Stress Corrosion of Austenitic Stainless Steel

Numerous investigators have reported stress corrosion of austenitic stainless steel in hot chloride solutions, usually concentrated solutions above 100°C and under conditions where oxygen was not deliberately excluded.

Several investigators have reported this type of cracking in wet, chloride-contaminated steam and in geothermal steam and high-temperature water.

(b) Stress Corrosion of Non-Ferrous Alloys

Various investigators have reported stress corrosion cracking of some non-ferrous alloys in geothermal fluids. These alloys are of minor importance in a geothermal plant.

3. HYDROGEN INFUSION

Numerous investigators have shown that corrosion by aqueous solutions containing H_2S causes infusion of hydrogen into steels, as indicated qualitatively by hydrogen probe activity (Marsh, 1954). Hydrogen infusion is known, in favourable circumstances, to cause blistering and embrittlement of steels, and to be associated with sulphide stress cracking and delayed fracture of stressed steels.

4. HYDROGEN-INDUCED DELAYED FRACTURE

Hydrogen infusion can produce delayed fracture in high-strength steels subjected to tensile stress. In fact the researches of many investigators suggest that sulphide stress cracking, delayed fracture, and hydrogen infusion are inter-related phenomena.

5. CORROSION-FATIGUE

Gilbert has drawn attention to the deleterious effects of simultaneous corrosion on the fatigue life of metals.

Experience with fatigue failure of blades in turbines operated on New Zealand geothermal steam suggests that corrosion fatigue is operative, but can be controlled by careful turbine design. Quantitative investigations are being undertaken.

GEOTHERMAL ECONOMICS
after
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1. GENERAL

The development of geothermal energy usually requires fairly heavy initial expenditure on exploration before the geothermal fluids start to flow in worthwhile quantities. If geothermal energy is to compete with fuel as a source of heat, it must be clearly demonstrated to be cheaper than the alternative after bearing its full share of these exploration costs. Even where the costs of exploration have been wholly or partly borne by some international organisation, these costs are just as real and should be taken into account when assessing the cost of the heat won.

An attempt will now be made to assess representative costs applicable to a 'typical' developed field. Such an attempt can only establish the order of magnitude of geothermal heat costs, but the exercise is worthwhile in that it enables a reasonable standard to be set up, against which the actual costs in certain fields may be compared.

2. COST COMPONENTS

The cost components that enter the reckoning of geothermal heat costs may be listed as follows:

2.1 Capital Costs

Exploration Costs:

Topographical and geological surveys, geophysical and geochemical investigations, exploratory drilling and field investigations.

Drilling Costs:

The sinking of production bores (including the costs of a certain proportion of bores which may prove to be failures) at locations which appear to have the greatest probability of achieving high production, as determined by the results of exploration.

Wellhead equipment costs:

The supply and installation of suitable valving, separators, silencers and instrumentation, with incidental integral pipework, at the wellheads of the successful bores.

Collection pipework costs:

The supply and installation of a suitable pipework system, with lagging, drainage and expansion facilities, for the purpose of collecting the geothermal fluids from the wellheads and delivering them to the point of need.

2.2 Recurring Costs

Interest on capital expenditure.
Depreciation of capital assets or amortisation of loans.
Maintenance and repairs of pipework, valves and wellhead equipment,
and possibly the maintenance of bores by descaling or the rectification
of fractures, etc.
Bore replacements, which may be necessary from time to time to make
good the loss of fluid yields from aging bores.
Salaries and wages of the operating, inspecting and supervisory staff.

All of these recurring costs are fixed, and totally independent of the quantity of heat yielded by the field and delivered to the point of use.

3. BASIC ASSUMPTIONS

3.1 Number of Production Bores in a Field

The cost of heat will clearly depend upon the number of successful production bores over which the exploration costs may be spread. At Wairakei in New Zealand there are more than sixty production bores; at the Geysers in California there are about the same number; at Larderello in Tuscany there are more than two hundred. It would be a cautious assumption, implying only a moderate scale of development, to assume a total of fifty bores (successfully productive) in the hypothetical field under consideration.

3.2 Heat Yield per Bore and Operating Pressure

These two parameters should be considered together because they are interdependent. Allowing for the tendency of steam yields to decline with time, and to become rather drier, and taking into consideration the modern trend to adopt rather moderate wellhead pressures so as to prolong the life of fields, a reasonable yield for a 'typical' bore might be taken at 100,000 lb/h of steam and 250,000 lb/h of hot water at a wellhead pressure of 75 psig.

As a first approximation, the heat yield from a typical bore may therefore be taken as follows:

	Flow lb/h		Enthalpy BTU/lb		Heat Flow BTU/h
Steam	100,000	x	1,151.1	=	115,100,000
Water	250,000	x	255.4	=	63,850,000
Total	350,000	x	511.3 (mean)	=	178,950,000

4. ESTIMATED THEORETICAL CAPITAL COSTS

4.1 Exploration Costs

A figure of $3 millions may be regarded as a conservative estimate for geothermal exploration. Spreading this cost over the assumed number (50) of bores, the exploration costs may thus be expressed at $60,000 per bore.

4.2 Drilling Costs

Assuming further that of every three bores sunk only two are successful and the third is a failure (in California and New Zealand a much higher success ratio has been achieved), the cost per successful bore may reasonably be taken at 3/2 x 60,000 or $90,000.

4.3 Wellhead Equipment Costs

An average figure of, say $35,000 per bore, would be reasonable.

4.4 Collection Pipework Costs

But first let it be assumed that the mean distance from the bores to the point of delivery is one mile. Next, combining the assumed well characteristics with the assumed number of bores, the total quantities of fluid handled will be:

Steam	50	x	100,000	=	5,000,000 lb/h
Water	50	x	250,000	=	12,500.000 lb/h

Assuming a maximum steam velocity of 150 ft/sec and a delivered steam pressure of 60 psig, the 5,000,000 lb/h of steam could be carried by eleven pipes of 30-inch internal diameter each at a cost of about $90 per foot.

$7,500,000

If the hot water is also transmitted to the same point of delivery, pipework of this size can be supplied and erected at about $120 per foot.

$2,700,000

To this must be added the costs of the terminal equipment such as pumps, head tank, flashing equipment and control gear which, based on the experience of the Wairakei experimental hot water transmission, may be valued at about $3 millions.

$5,700,000

Adding to this the cost of the steam transmission a total heat transmission cost is arrived at of $13,200,000, or $264,000 per bore.

5. CAPITAL CHARGES

There is usually a tendency for a bore's output of heat to decline in the course of time at rates which vary from field to field but which may be of the order of 5% to 10% per annum. The assumption of typical fluid yields is intended to be applied to average figures during the life of each bore. Occasionally a bore may fall out of action altogether as a result of changes in the aquifer, persistent blockage or other cause. Although bores should generally remain productive for much longer than ten years, it would be a cautious assumption to assign this life to them. Wellhead equipment and collection pipework on the other hand should be capable of extremely long lives, but a conservative figure of 25 years is proposed simply because the life of the field itself is to some extent uncertain. Based upon experience in Italy, New Zealand and elsewhere, 25 years would seem to be a very conservative figure. For the same reason it would be wise to assume that the costs of exploration are amortized over 25 years.

6. COST OF HEAT AT THE BORES

Experience shows that, for power generation at any rate, a bore load factor of 90% is quite realistic. The costs have also been deduced on the alternative assumptions that only the steam is used and that the heat of the total fluid is used.

By adding to the heat costs at the bores the capital charges and other costs arising from the fluid collection and transmission system, it is possible to estimate the cost of heat at the point of delivery. In this reckoning it is assumed that 7½% of the heat is lost in transmission, largely apparent as steam condensation. This is a conservative allowance.

The figures show that if the heat of all the bore fluid is used, it should be possible to obtain geothermal heat at a cost of the order of U.S. cents 2 per million BTU at the wellheads and at about U.S. cents 4 or 5 per million BTU if the heat is collected and piped to a single point about a mile away. If only the steam is used, these costs would be increased by about 50% at the bores and about 15% at the point of delivery.

These theoretical costs are based upon certain assumptions which, on the whole, have been cautiously chosen. Although in some fields the heat costs would be higher, it is possible that in others they could be lower.

7. ACTUAL HEAT COSTS

It is now of interest to examine such heat costs as actually occur in existing exploited geothermal fields.

7.1 Larderello

The cost of steam heat at the bores is probably about U.S. cents 2.9 per million BTU reckoned at an interest rate of 6%. If adjusted for interest at 8%, this cost would rise to about U.S. cents 3.2 per million BTU.

7.2 Rotorua

Heat cost at the wellhead at Rotorua in New Zealand have been quoted at U.S. cents 3.36 per million BTU. By comparison, a figure of U.S. cents 67 per million BTU is given for oil fuel heat at the same place, which shows how very cheap geothermal heat can relatively be.

7.3 Wairakei

On a basis of 8% interest, 90% load factor, a ten-year bore life and a 25-year life for

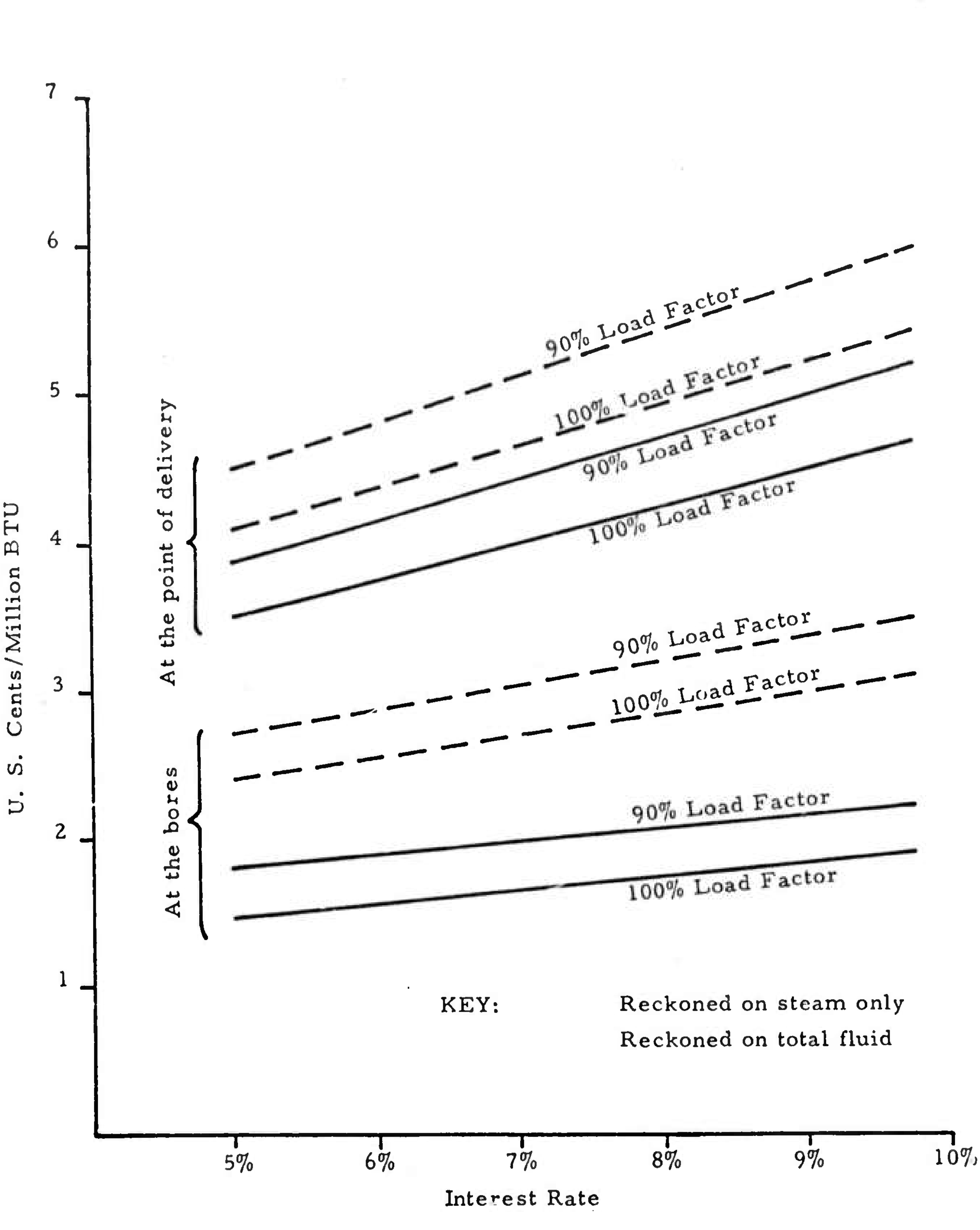

Figure 2. THEORETICAL HEAT COSTS

other assets it can be shown that the cost of heat in the total fluid at the bores is about U.S. cents 2.65 per million BTU. The cost of steam heat delivered at the plant is estimated at about U.S. cents 13.3 per million BTU as against a theoretical figure of U.S. cents 5.5 per million BTU.

7.4 The Geysers, California

At this plant it is only possible to estimate the *price* of heat, as distinct from the *cost*, because the steam is retailed in bulk by a commercial supplier to the users, The Pacific Gas and Power Company. From the price of 2½ mils per kWh charged for steam it is a simple matter to deduce that the price of steam heat is about U.S. cents 12½ per million BTU delivered to the plant.

8. POWER HOUSE PLANT, INCLUDING BUILDINGS AND COOLING WATER FACILITIES

Based on existing geothermal installations, the following costs may be taken as reasonable. It will be noted that they are less sensitive to scale than conventional thermal plants, owing to the need to use units of farily moderate size even for large total installed capacities:

For 20 MW installed	U.S. \$160/kW
For 50 MW installed	U.S. \$140/kW
For 100 MW installed	U.S. \$125/kW
For 200 MW installed	U.S. \$110/kW

9. OPERATION, REPAIRS AND MAINTENANCE

Based on experience, the following figures may be taken as reasonable:

Installed capacity	20 MW	50 MW	100 MW	200 MW
Operations, repairs and maintenance in \$p.a./kW	3.7	3.0	2.6	2.25

Table 3. APPROXIMATE COSTS OF GEOTHERMAL HEAT IN PRACTICE AND THEORY
(U.S. Cents per Million BTU)

Basis		Larderello (power)	Rotorua (air conditioning)	Iceland (district heating)	Wairakei (power)	Geysers (power)	Theoretical[5]
Cost at wellheads	steam only	3.2[1]	3.36	N.A.	6.90	N.A.	3.3
	total fluid				2.65		2.0
Cost at single collection point in thermal field				7.5 to 12.1			
Cost at single delivery point		N.A.		13 to 14[2]	13.3[4]	12.5[6]	7.31[4]
Cost at point of use		N.A.		102[3]			

[1]With a dry field the cost of steam and of total fluid are of course the same.
[2]Cost delivered in bulk in Reykjavik, excluding distribution to local consumers.
[3]Average cost delivered to domestic consumers.
[4]Steam heat only. Delivered at power station.
[5]Wet field assumed.
[6]Purchase price of steam.
N.A. Not available.
Interest is taken at 8% p.a. for Larderello, Wairakei and Theoretical.
Elsewhere, the rate of interest has not been specified.

Table 5. COMPONENT AND TOTAL KILOWATT COSTS FOR GEOTHERMAL POWER

Output	20 MW	50 MW	100 MW	200 MW
	$/kW	$/kW	$/kW	$/kW
Cost Summary:				
Exploration	150	60	30	15
Drilling	18	16.2	16.2	15.7
Wellhead gear & collection pipework	59.8	53.8	53.8	52.4
Plant, etc.	160	140	125	110
	387.8	270	225	193.1
Add 20% for interest during construction and contingencies	77.6	54	45	39.5
TOTAL	465.4	324	270	232.6

Table 6. THEORETICAL GEOTHERMAL PRODUCTION COSTS

Installed Capacity	20 MW	50 MW	100 MW	200 MW
	$p.a./kW	$p.a./kW	$p.a./kW	$p.a./kW
Interest at 8%[1]	37.23	25.92	21.6	18.61
Amortization on sinking fund basis:				
Bores (10 years)[1]	1.49	1.34	1.34	1.30
Other assets (25 years)[1]	6.07	4.17	3.43	2.92
Operation, repairs and maintenance	3.70	3.00	2.60	2.25
Alterations to wellheads, etc.	0.30	0.27	0.27	0.26
TOTAL	48.79	34.70	29.24	25.34
Equivalent cost/kWh in U.S. mils at 85% plant factor	6.55	4.66	3.93	3.41

[1] Including 20% for interest during construction & contingencies.

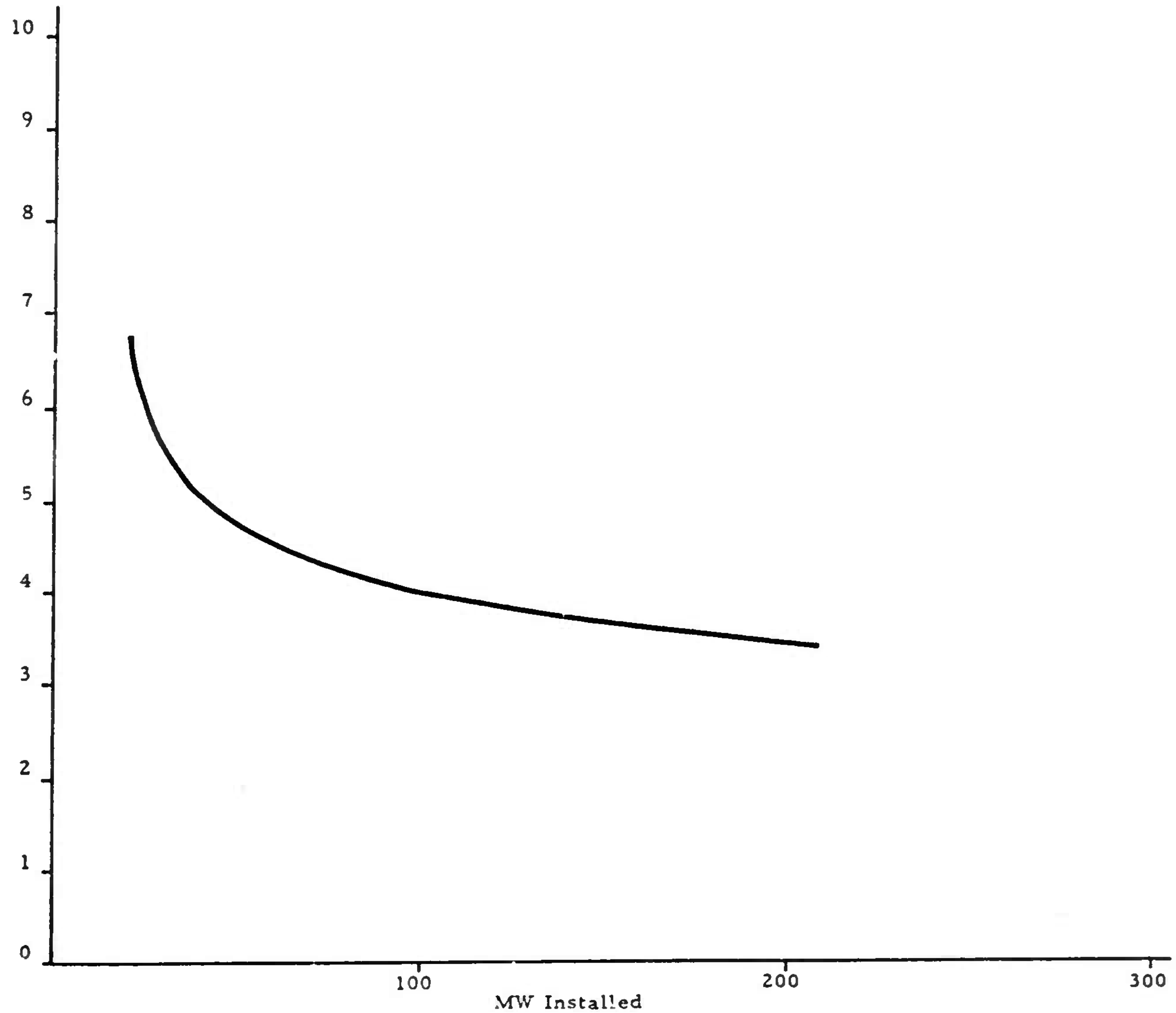

Figure 5. THEORETICAL GEOTHERMAL POWER PRODUCTION COSTS

10. ACTUAL COSTS OF GEOTHERMAL POWER

Not very much data are available of geothermal power costs achieved in practice, and where costs have been quoted there has often been no mention of the assumed rate of interest or of the assumed asset lives. However, the following figures may be of some interest.

10.1 Wairakei

Electrical energy is being generated at Wairakei (192 MW installed) at a cost, adjusted for 8% interest, and assuming a bore life of ten years and a life of 25 years for other assets, of 5.14 mils/kWh. This is nearly 50% more than the theoretical, but the pipe route length is very long and the early evolution of the plant was complicated by a planned chemical plant which never materialised.

10.2 Larderello (390 MW Installed)

The cost of electricity is believed to be considerably cheaper than in New Zealand. Facca and Ten Dam have estimated, on an assumed interest rate of 6%, a generating cost of 2.6 to 2.74 mils/kWh for non-condensing plants and 2.38 to 2.96 mils/kWh for condensing plants.

10.3 The Geysers, California (81 MW Installed)

A cost of 4.81 mils/kWh has been quoted with fixed charges for return and depreciation at 8.57% p.a. Considering that in this case the steam has to be bought in bulk from a commercial supplier at 2½ mils/kWh generated, this overall cost is astonishingly low.

10.4 Namafjall, Iceland

For a small non-condensing set of only 2½ MW production costs have been quoted at 'from 2½ to 3½ mils/kWh,' but the underlying assumptions are not known.

10.5 Pauzhetka, Kamchatka, U.S.S.R.

An energy cost of only 7.2 mils/kWh has been quoted for this plant but without any underlying parameters being specified. Considering the small size of the plant (5 MW) and the very remote situation, this price can be regarded as low. It is claimed that the cost is 30% lower than could be achieved by an alternative means of power supply in the same area.

All these power costs are somewhat inconclusive, but they show that the theoretical costs derived earlier are not unrealistic.

11. ECONOMIC ASPECTS OF GEOTHERMAL POWER

Another aspect of geothermal power generation that may yet become important is in the use of secondary fluids (e.g., freons) as working media instead of water. The attractions of doing this are that a greater proportion of the available heat can be extracted from geothermal fluids--particularly if at relatively low temperatures–by means of heat exchangers, and that physically smaller turbines can be used by virtue of the relatively high vapour pressures of the secondary fluid. As against these advantages, however, costly heat exchangers and condensers have to be used, and special precautions have to be taken to avoid leakage of the secondary fluid to the atmosphere. Although some interesting experiments have been carried out in this direction, economic data are at present lacking (Pessina *et al.*, 1970; Moskvicheva, 1970).

12. INDUSTRIAL AND OTHER APPLICATIONS OF GEOTHERMAL HEAT

Besides district heating, power generation and desalination, geothermal energy could be used for a great many heat consuming processes, of which the following is but an incomplete list:

Sugar processing in conjunction with paper manufacture from bagasse
Paper manufacturing from wood pulp
Total gasification of coal (Lurgi process)
Salt production
Borax production
Powdered coffee production
Dried milk production
Cattle meat from Bermuda grass
Rice parboiling
Textiles
Fruit or juice canning or bottling
Other food processing, canning or crop drying
Plastics
Timber seasoning
Fish drying and fish meal production
Recovery and processing of certain minerals (e.g., diatomite)
Refrigeration
Air conditioning
Horticulture and raising of vegetables under glass
Heavy water production
Recovery of valuable trace elements from geothermal waters

Hitherto, not many of these applications have been put to practical use, but greenhouse heating is extensively practised in Iceland and the U.S.S.R., air conditioning is done in New Zealand, there is a very large paper manufactury in New Zealand, a diatomite recovery and processing plant has been established in Iceland, and plans have been drawn up for heavy water production in Iceland–all making use of geothermal energy.

The actual production costs of these industries are of little significance in the context of this article, but the point of importance is that these production costs are in every case lower than could be achieved by alternative means; and this arises from the fact that geothermal heat can be so very much cheaper than heat obtained from fuel. There is undoubtedly a wealth of potential for geothermal heat to be used for industrial purposes.

MANAGEMENT OF A GEOTHERMAL FIELD
after

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1. PRIMARY EFFECTS OF EXPLOITATION

The number of geothermal fields under exploitation is increasing, but at present there are few with a production history indicating the effects of exploitation. The examples discussed below are the Wairakei field in New Zealand, the Larderello field in Italy and the Laugarnes field in Iceland. The first is basically a high temperature hot water system, the second a dry steam system and third a low temperature (less than 150°C) hot water system. In this respect, they can be regarded as typical of the three main types of geothermal systems.

1.1 Wairakei

The production history of this field extends over nearly 20 years, and in that time substantial changes have taken place in the underground conditions. Bolton (1970) gives a detailed description of the behaviour of the field under exploitation. The production aquifer is a breccia about 1,500 ft thick, overlain by a mudstone/siltstone formation which acts as a cap rock. Useful production is obtained from the breaccia, but the best production is from the contact between the breccia and the underlying ignimbrite at a depth of about 2,000 ft. Initially, the aquifer was filled with water, temperature and pressure conditions following the boiling point for depth relationship. The maximum temperature measured in the field was 260°C.

1.2 Larderello

This field has been under exploitation for many years, initially for the recovery of chemicals, and since the mid 1920's, for the generation of electricity. As at Wairakei, substantial changes have taken place. It has not been the practice at Larderello to measure formation temperatures and pressures, but the nature of the field is such that changes in formation conditions can be inferred from wellhead measurements.

In lightly exploited areas, the output of a well will remain constant for ten years. The life of a steam well at Larderello is estimated to be 20 years (Chierici, 1964) but some are still discharging after 30 years, although at a greatly reduced output.

The most significant change which has taken place in the Larderello field is that whereas the discharge from the initial deep bores was saturated steam, it is now dry with an appreciable amount of superheat. This is attributed by Chierici (1964), and Ferrara *et al.* (1970) and others to a gradually receding boiling water surface at depths in excess of 2 km, the steam from which is superheated by passing through layers of rock which, due to their poor conductivity, have retained heat.

A feature of the management of the Larderello field has been the need for a continued programme of drilling to maintain the total output, the newer wells being drilled relatively deeper. At present a number of production wells are operating close to their shut-in pressure, and exploration is continuing at still greater depths with the object of locating higher pressures.

1.3 Laugarnes

This field has been under exploitation since 1928 for district heating in the city of Reykjavik. Initially, production was from shallow artesian wells, but since 1962 has been wholly by pumping from deep wells. The behaviour of this field, together with a comprehensive analysis covering the period 1957 to 1969 is described by Thorsteinsson and Eliasson (1970).

Production is from three aquifers. Temperatures in the upper aquifer, which is about 200 m below ground level are 110-120°C. In the centre aquifer, the temperature is 135°C and in the lower, about 2,200 m below ground level, 146°C. From 1957 to 1962, withdrawal rates were relatively uniform as the flow was mainly artesian. Since 1962, following the introduction of deep well pumping, the flow has varied seasonally, the winter flow being about 3 times the summer flow. The winter peak draw-off is accompanied by a draw-down

in aquifer pressures, but this draw-down is almost entirely recovered during the summer. From January 1957 to August 1969, the net decline in pressure was equivalent to 66.8 m waterhead. No effect on temperatures at depth has been reported.

1.4 Summary of the Primary Effects of Exploitation

The substantial exploitation of any underground fluid will result in a decline in pressure of the system, and geothermal systems are no exception to this rule. In the case of fields discharging under thermo-artesian conditions, outputs also fall. The extent of the fall in output and pressures is governed by the rate of replacement of the discharged fluids, which in turn is a function of the permeability of the system as a whole. At present, the magnitude of these effects cannot be predicted from early investigations, and can only be assessed after a period of exploitation. This is the fundamental reason why a geothermal field must be developed in stages.

In thermo-artesian systems, the discharge capacity of individual wells decreases with increasing exploitation. This indicates that when selecting an operating pressure, the lowest pressure consistent with the other factors influencing the choice should be adopted, as this will give the longest operational life for the individual wells.

In a high temperature hot water system such as Wairakei, in which saturation conditions apply in the upper levels, the fall in pressure must inevitably be accompanied by a fall in temperatures at these levels. The heat stored in the formation rock will tend to sustain temperatures causing a lag between the temperatures and pressure declines. Similar effects are shown by a steam system, but in this case the effect on temperature will be less pronounced. There can, however, be a substantial increase in enthalpy.

With non-thermo-artesian systems developed by deep well pumping, the effects of exploitation on output are obscured by the pumping, but there will nevertheless be a decline in pressures. In this type of system, where saturation pressures for the measured temperatures are considerably lower than the hydrostatic pressure, it is unlikely that steam will form in the formations. Consequently, the principles of flow in porous media can be successfully applied, as has been done for the Laugarnes field.

2. SECONDARY EFFECTS OF EXPLOITATION

2.1 Natural Activity

The effects of exploitation on natural activity differ according to the nature of the field, and the time the field has been exploited. At Larderello, which has been exploited to varying degrees for over 100 years, the flow of heat from many of the areas of intense natural activity has almost disappeared (Elder, 1966). At Wairakei on the other hand, heat flow measurements, in 1958 showed that the natural heat flow had not changed since 1952 although the field output was over 1½ times the natural discharge (Ferrara *et al.*, 1970). Subsequently, the field output has reached 6 times the natural discharge and, although no precise measurements are available, there is no noticeable decrease in the natural heat discharge. There has, however, been a noticeable increase in the enthalpy of the discharge. This is evident in the decline in or cessation of discharge from hot pools and spings, and an increase in area and intensity of heat escape from steaming ground, occasionally accompanied by small eruptions.

2.2 Ground Movement

Ground movement has occurred after exploitation of many cold water aquifers and oil fields, the most well known examples of each probably being Mexico City, and Long Beach, California. The only similar effect so far reported for a geothermal field has been that at Wairakei (Hatton, 1970; Smith, 1967).

The movement at Wairakei has a strong vertical and horizontal component and has formed a roughly elliptical dish-shaped depression The maximum rate of subsidence has been about 1.3 ft a year, with a total maximum subsidence estimated to be over 10 ft. The centre of the subsidence is about 1,500 ft from the nearest wells, and 6,000 ft from the region of greatest draw-off. The movement is attributed to the bending of the mudstone cap rock resulting from the fall in pressure and the withdrawal of the large mass of fluid. Precise measurements taken by tiltmeter during the partial shut down in 1968 suggest that the subsidence may be reversible.

The ground movement has affected steam mains and drainage channels with some inconvenience, but without jeopardizing the operation of the field. However, the effect of the movements measured at Wairakei on powerhouses or similar structures would be little short of disastrous. For this reason, the possibility of ground movement must always be

considered, and a comprehensive system of bench marks installed in sufficient time to enable potential areas of subsidence to be located before the powerhouse site is committed.

2.3 Pollution

The main types of pollution likely to be encountered are atmospheric from the disposal of gas, thermal from the waste heat, and chemical from the dissolved salts in the waste water. One or more problems arising from the effects of pollution is likely to be encountered in any geothermal field. The extent and detailed nature of the problem will vary considerably for each field, and solutions must therefore be determined according to the circumstances pertaining to each field.

In general, the quantities of gas discharged are relatively small, and atmospheric pollution is not a serious problem provided the gases are vented at a height above that of structures in the vicinity. However, care must be taken to avoid dangerous accumulations of gas arising from leakages in the steam or hot water system. All leaks should be detected and remedied as quickly as possible; ventilation should be provided in all potentially dangerous areas; and personnel should have available, and should use, gas detectors.

Thermal pollution can be a problem when local rivers or streams are used for disposal of the waste water. Fish life may be affected, and the growth of water weed encouraged. This is a complex problem with many inter-related factors, and if it is likely to be serious, a specialist's advice should be obtained.

Chemical pollution is normally a relatively minor problem in fields producing steam, but White (1970) mentions that pollution by boron and ammonia is now requiring preventative treatment at The Geysers, California. The solution adopted is the injection into the reservoir of the condensate containing the pollutants.

2.4 Chemical Deposition

Reduction of output due to chemical deposition in the wells has occurred in several fields, but removal of the deposits has been a straightforward process, and in most cases the output has been fully restored. One example is described by Cataldi *et al.* (1970). Deposition normally takes place at the level of boiling in the well which, as pressures decline due to exploitation, becomes progressively deeper. Ultimately, boiling and deposition will take place in the formations (Smith, 1967). At present, no evidence has been reported of chem-

ical deposition in the formation having a detrimental effect; it can therefore be inferred that such deposition is a long term effect.

Chemical deposition can also be a problem in the disposal of waste water. At Wairakei, silica deposits in the waste water channel must be removed annually. There is little difficulty involved in this, although there is some expense. However, at the Otake field in Japan, Yanagase *et al.* (1970) describe a problem in which a pipeline carrying waste water was rendered useless after a relatively short period of operation due to chemical deposition. From their investigations into the conditions under which deposition occurs, they have concluded that if a retention time of 1 hour is provided, together with agitation during retention before the waste water enters the pipeline, deposition will be greatly reduced.

3. MEASUREMENTS AND RECORDS REQUIRED

Except for low temperature geothermal fields, where the established theory of single phase flow in porous media can be applied, geothermal field management lacks the aid of the powerful mathematical tools available, for instance, in the management of oil and gas reservoirs. Notwithstanding this lack, the management of a geothermal field still requires the accumulation and assessment of data on which are based the decisions concerning the initial methods of exploitation, and the maintenance of or modifications to these methods as exploitation continues. The data are also essential in the development and testing of the relevant theory.

3.1 Field Output

The total mass and heat discharged from the field is fundamental both to field management and to development and testing of theory. For this purpose, a continuous record should be kept of the periods and rate of discharge for individual wells.

3.2 Well Output Characteristics

Periodic measurements of the mass and heat outputs over the range of possible wellhead pressures are necessary to check the variations which take place consequent on changes in field conditions.

3.3 Wellhead Pressure

This is of fundamental importance because it serves as a reference base when describing surface conditions, and in many cases when describing underground conditions also. It should be measured every time any measurement of any sort is made on a well.

3.4 Wellhead Temperature

In the case of high temperature hot water fields, this measurement is not so essential because, particularly when discharging, saturation conditions can reasonably be assumed and wellhead temperatures obtained from the measured pressure. For dry steam and low temperature hot water fields, this cannot be assumed, and in these cases, wellhead temperatures should be measured.

3.5 Static Downhole Pressures and Temperatures

These measurements, taken in a shut-in well in which conditions are relatively stable, are a direct indication of changes in underground conditions. As it is often impossible to ensure that truly stable conditions apply, considerable care is necessary when interpreting these measurements. To obtain a reliable indication of changes in field conditions, measurements should, in general, be taken at two to three monthly intervals in a number of wells, and in every well at least once a year. The frequency of measurement should also reflect the rate at which changes are occurring, and the degree of uniformity between measurements on different wells.

3.6 Pressures and Temperatures during Discharge

These measurements, taken on individual wells, give information on feeding conditions to the well. For instance, measurements at Wairakei after some years of exploitation show that the temperature of the fluid feeding some of the wells differs from the formation temperature as measured in a static run. Also, pressure measurements during discharge may indicate whether permeability is changing. These measurements are not required regularly, but should be taken as the opportunity offers, particularly if changes of this nature are suspected.

3.7 Geochemical Measurements

Geochemistry is discussed elsewhere in this volume, but it should be mentioned here that the chemistry of the field discharge can provide much useful information on field behaviour, and regular monitoring is desirable.

3.8 Gravity Measurements

Hunt (1970) describes a method not yet completely proven, but which looks very promising for assessing the net mass withdrawal from a field. This, by comparison with the total draw-off, gives an independent assessment of the extent to which inflow may be influencing conditions. The gravity measurements described for Wairakei suggest that inflow has a significant influence, providing confirmatory evidence for the conclusions drawn from the response of pressures to mass draw-off.

3.9 Ground Level Measurements

These measurements are important early in the life of a field, preferably covering a period of substantial draw-off, and before sites are selected for the main structures. The frequency of subsequent measurements will depend on the extent and rate of movement, and the potential danger to steam mains or other works likely to be affected. Initially, measurements at about two-year intervals should be sufficient.

3.10 Accuracy and Interpretation of Measurements

Having undertaken a series of measurements, frequently with high quality instruments, there is always a strong tendency to accept without question the accuracy and reliability of the results. This tendency must always be guarded against, as there are many factors which can influence the accuracy. For this reason, every opportunity should be taken to make independent check measurements. For example, wellhead pressures can serve as a check on downhole pressure and temperature measurements, the former directly, the latter through the saturation pressure/temperature relationship if this applies. Again, the enthalpy from output tests can often, especially in the early days of exploitation, be checked against

downhole temperatures. Any measurement of doubtful accuracy should be discarded, and a repeat measurement made.

Finally, when satisfied as to the accuracy of a particular measurement, or series of measurements, the results must be interpreted with a knowledge of all factors which could have influenced those measurements. This applies particularly when the results lead to unexpected conclusions, or conclusions at variance with past experience. Too often, neglect of this elementary principle can lead to erroneous conclusions.

Appendix B

Ultra-Deep Drilling
for Geothermals

Excerpt of Technical Discussion
from "Progress Report"
28 February - 31 March 1973

Well Planning

One of the most severe problems in deep drilling is the lack of planning in advance of actual drilling operations. The solution to this problem is to have a good well plan assembled by a drilling coordinator. This coordinator must draw upon the knowledge of those familiar with the following types of information:

1. Geology
2. Geophysics
3. Lithology
4. Mechanics
5. Hydraulics
6. Drilling Engineering
7. Supervision and Logistics

To develop the best drilling plan, he should construct a chart similar to that shown in Figure B-1. Shown in this chart are the basic curves needed to plan for current drilling practices. The first curve is that of "rock pore fluid pressure" versus depth. Pressures are expressed in equivalent heads of drilling mud in pounds per gallon. This curve is developed from geophysical, geological, and well log data and indicates what the well bore mud weight must be to prevent a blowout. The mud weight must always be in excess of the pore pressure equivalent for any given depth. These pressures divided by their respective depths are fracture gradients and are expressed in equivalent pounds per gallon of drilling mud head. The gradient curves show the minimum and maximum pressures required to split open the wellbore.

The actual mud weights used in drilling must not allow the well to blow out, while at the same time not be too heavy and cause fracturing and lost circulation below the last casing depth. Drilling mud is still essential for deep drilling. The mud provides hole stability, removes the cuttings, and cools the bit. The casing program, shown in Figure B-1, is controlled by the mud weight program.

Planning a program for an ultra-deep well is an important task that must encompass considerably more than the information shown in the figure. Many additional facets of the problem that must be considered are discussed in the following sections.

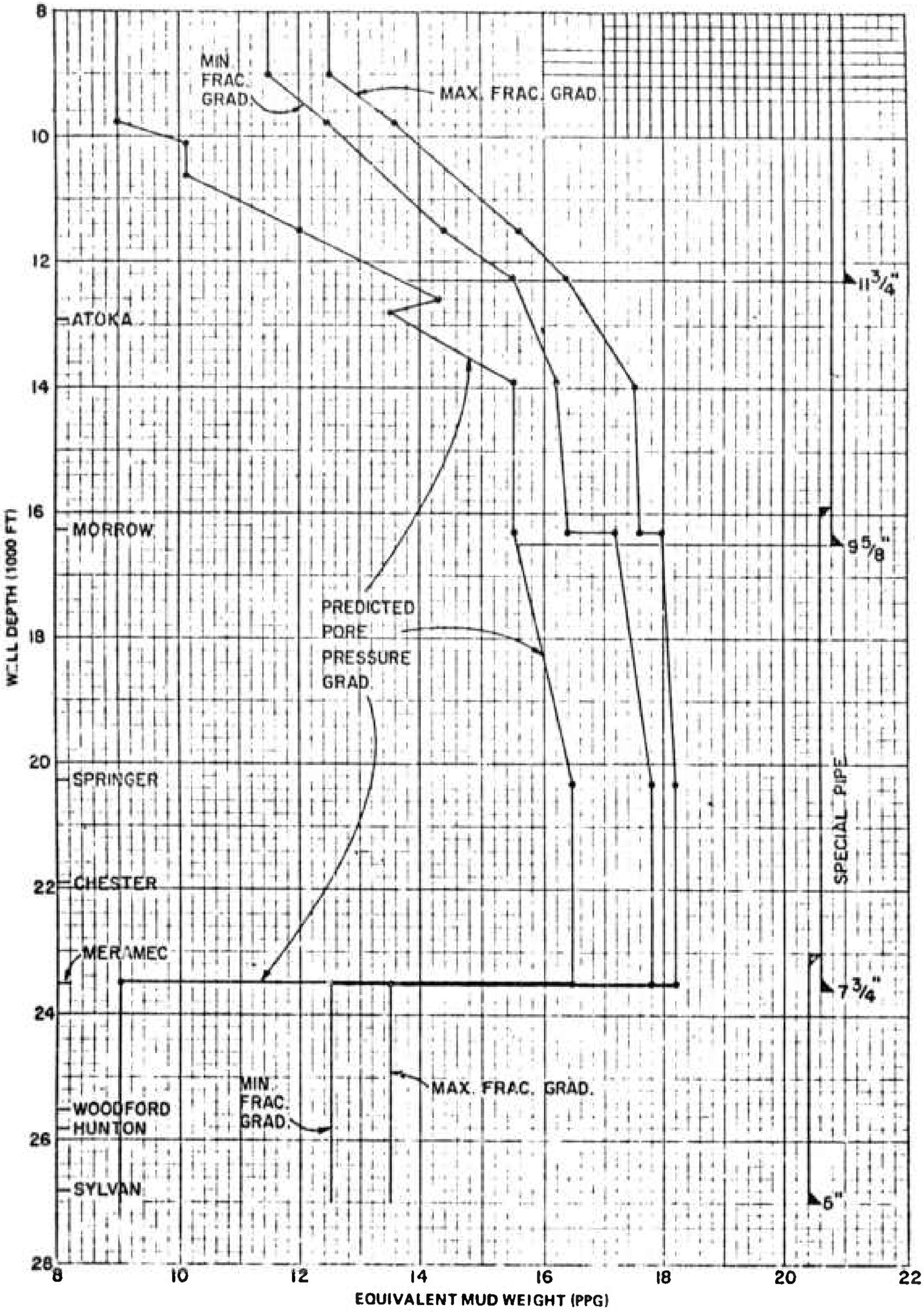


Figure B-1. WELL PLAN

Current Operational Drilling Rigs

There are, at the present time, rotary rigs capable of drilling to 40,000 ft. One such rotary rig has been used to drill a well to 30,050 ft and is currently drilling a second ultra-deep well (rig "C" in Table B-1). Table B-1 shows the rig specifications for three of the world's most powerful rotary drilling rigs (Loffland Brothers Drilling Co. is the leader in this field). Undoubtedly, these specifications must and will be increased for ultra-deep drilling in the future.

A rig for drilling to over 30,000 ft requires a large surface area for its operation. A typical rig layout is shown in Figure B-2. Similar configurations will probably be used in the future.

Table B-1. TYPICAL BIG RIG HARDWARE NOW AVAILABLE

Item	Rating		
	Rig A	Rig B	Rig C
Mast	147 ft, w/1.3 million-lb GNC	147 ft, w/1.3 million-lb GNC	142 ft, w/2 million lb GNC
Draw works	3000 hp	4000 hp	3000 hp
Substructure	32 ft high, w/750,000-lb setback capacity	32 ft high, w/750,000-lb setback capacity	28 ft high, w/1.1 million-lb setback capacity
Rotary	37½ in., 500 ton	37½ in., 500 ton	37½ in.
Primary mud pumps	2 at 1400 hp each	1 at 1750 hp 1 at 1000 hp	2 at 1650 hp each
Traveling block, hook	525 ton	525 ton	750 ton
Swivel	400 ton	400 ton	650 ton
Wire line	1½ in.	1½ in.	1-5/8 in.

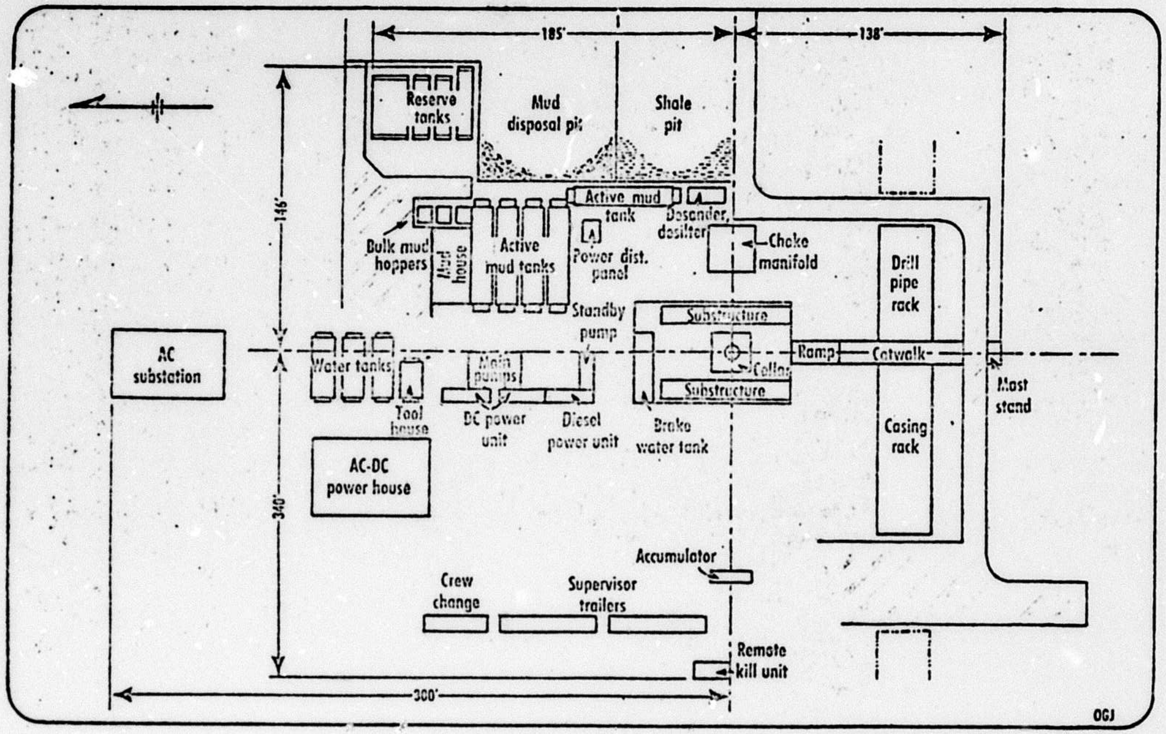


Figure B-2. LAYOUT FOR WELL DRILLED TO RECORD 30,050 FT

Tubular Goods

Oilfield tubulars that are currently available could be used to case a well to a depth of 40,000 ft or deeper. Special techniques, such as running liners to bottom on drill pipe, cementing it in place, and then tying the liner back to the surface, will be required. This is due to the high tensile loads imposed upon the upper portions of full, long casing strings while they are being run. Special sizes of casings have been developed to accommodate more standard bit sizes in deeper drilling. Undoubtedly, additional casing sizes and high-strength grades of steel will be developed in the future. Table B-2 indicates some typical pipe weights which must be handled by a modern drill rig. Figure B-3 shows the total casing program as it was implemented in the 30,000-ft Baden well.

Drill Pipe

Drill pipe for conventional drilling has been developed to the point that a tapered string would drill to more than 40,000 ft. However, if a bit should become stuck at great depth, little additional strength would remain in the drill pipe to pull the bit loose. Again, higher strength steel has been developed for drill pipe, and additional grades and sizes will be developed as the need arises (Hughes Tool Company and Reed Drilling Tool Company of

Table B-2. TYPICAL PIPE WEIGHTS THAT MUST BE HANDLED

Pipe Size (in.)	Weight (lb/ft)	Depth (ft)	Weight (lb)
3½ (drill pipe)	15.50	30,000	465,000
4½ (drill pipe)	20.00	30,000	600,000
5½ (drill pipe)	24.70	30,000	741,000
5 (casing)	18.00	30,000	540,000
8-5/8 (casing)	49.00	21,000	1,029,000
11-3/4 (casing)	60.00	15,000	900,000
	Example of Tapered Drill String to 30,000 ft		
3½	15.50	10,000	
4½	20.00	15,000	578,500
5½	24.70	5,000	

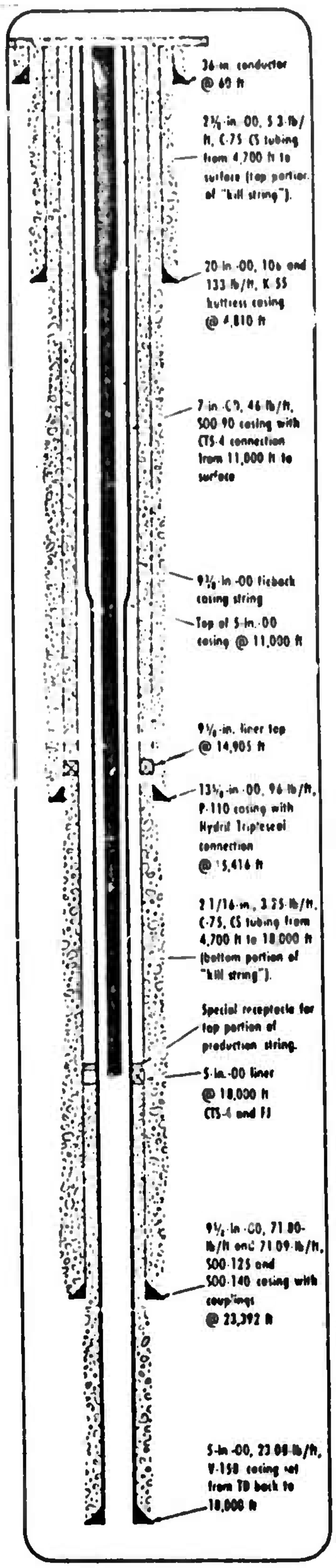


Figure B-3. CASING IN NO. 1 BADEN

Houston, Texas, are in the forefront on this development). Table B-3 shows the maximum length of common drill pipe that can be suspended before deforming under its own weight: Table B-4 shows how different grade and size drill steels must be combined to make it possible to attain depths in excess of 30,000 ft, and in addition to deliver 100,000 lb of pull at the drill bit.

In ultra-deep drilling, because of the instability of the rock, it may become difficult, if not impossible, to remove the drill pipe for bit changes, logging, or casing. One of the novel technology developments foreseen is one-way drill pipe, which is advanced to the greatest attainable depth and is then cemented into place, after removal of the drill bit from the inside of the pipe. The drill pipe then takes on the role of the casing string for the protection of the next length of drill string, which eventually becomes a casing string. Such technology, if developed and made operational, may permit drilling even in plastic, incompetent formations, and the advancement of a telescoping hole to the required ultra depth. However, at present this is merely a suggestion, even though some producing wells have operated using a drill pipe that was modified for the purpose.

Drill Bits

Today's drilling bits are much improved over those of only a few years ago. The new journal bearing bits with tungsten carbide inserts for cutting have provided reasonable penetration rates at the 25,000- to 30,000-ft level. The bearings allow for 50-60 hr of on-bottom drilling per bit, even in such hostile environments. It is believed that currently available bits could drill to 50,000 ft. Average penetration rates, footages, and other data taken from the 520°F Falcon-Seaboard "Tally" well are shown in Table B-5.*

Bit Trip Times

Time spent in pulling a worn bit out of a well, replacing it, and running the new bit back in the hole, is wasted as far as actual drilling is concerned. Such "round trips" represent a large percentage of the overall time spent in drilling any well, as shown in the data in Table B-6 taken from Falcon-Seaboard's Tally well. Further, a great deal of downhole problems are caused, or at least occur, while round tripping. Therefore, the ultimate goal is to eliminate round trips. To date, this has not been possible. However, there are many ideas as to how trips could be decreased both in number and time. Among these are:

*For an API-classified, recommended drill bit program and drill bit capabilities under standard conditions, see Table B-12.

Table B-3. MAXIMUM LENGTH OF COMMON GRADE E DRILL PIPE SUSPENDED IN AIR BEFORE PERMANENT DEFORMATION OCCURS

Pipe Size (in.)	Grade	Weight (lb/ft)	Tensile Strength (1000s lb)	Maximum Length Before Deformation (ft)
2-7/8	E	10.40	214	20,577
3½	E	15.50	323	20,838
4½	E	20.00	412	20,600
5½	E	24.70	497	20,121

Table B-4. SINGLE-SIZE DRILL STRINGS CAPABLE OF DRILLING AT 30,000 FT (100,000 lb of Pull Available at Bit)

Pipe Size (in.)	Weight (lb/ft)	Grade	Length (ft)	Attainable Depth (ft)
4¾ x 2 Drill Collars			600	
3½	9.5	E	9,520	
	9.5	G	9,550	
	15.5	E	3,550	
	15.5	G	3,260	
	15.5	S	8,340	34,820
7½ x 2½ Drill Collars			600	
4½	16.6	E	10,500	
	16.6	G	3,270	
	16.6	S	7,970	
	18.1	S	3,550	
	20.0	S	4,960	30,850
8½ x 3 Drill Collars			800	
5	16.25	E	5,300	
	16.25	G	9,430	
	16.25	S	8,080	
	19.50	S	7,450	31,060

Table B-5. BITS USED AND HOW THEY PERFORMED

Interval (ft)	Number of Bits	Size (in.)	Average Penetration Rate (ft/hr)	Average Footage (ft)	Weight on Bit (lb)	rpm
0- 119	1 fishtail	27				
119- 3,675*	2 rock	15	70.5	1,778	12,000-15,000	225
3,675-12,520	10 rock	14¾	24.3	884.5	10,000-50,000	100-175
12,500-19,750	31 rock	9½	9.32	197.5	15,000-40,000	80-125
	2 diamond	9½	2.56	547	35,000	120-140
	1 diamond core	7-13/16				
	1 rock	9½		Used for drilling at top of line		
19,750-23,884	1 rock	6½	1.92	25	25,000	90
	1 diamond core	6-7/16	2.42	175	10,000 12,000	100
	5 diamond	6½	3.92	774	12,000-15,000	150
	1 junk mill	6-3/16		19		

*15-in. hole opened to 22 in. with one pilot bit.

Table B-6. OPERATION ALLOCATION PERCENTAGES OF THE 228½ DAYS ON THE TALLY WELL

Operation	Percentage of Total Time
Drilling and reaming	50
Trips	20
Maintenance and revision of equipment	8
Logging, coring, etc.	8
Circulating, conditioning hole and mud	5
Running, casing and cementing	8
Fishing	1

- better bits that drill faster and longer,
- bits that could be replaced by wire line through the drill pipe,
- a means of pulling longer stands of drill pipe. For example, trips could be faster if the drill pipe could be rolled up on a spool, or pulled in 1000-ft segments rather than the conventional 93-ft stands.

The actual trip times versus depth for the world's deepest well are as follows:

Depth (ft)	Trip Time (hr)
10,000	8
15,000	13
20,000	18
25,000	20.5
30,000	22

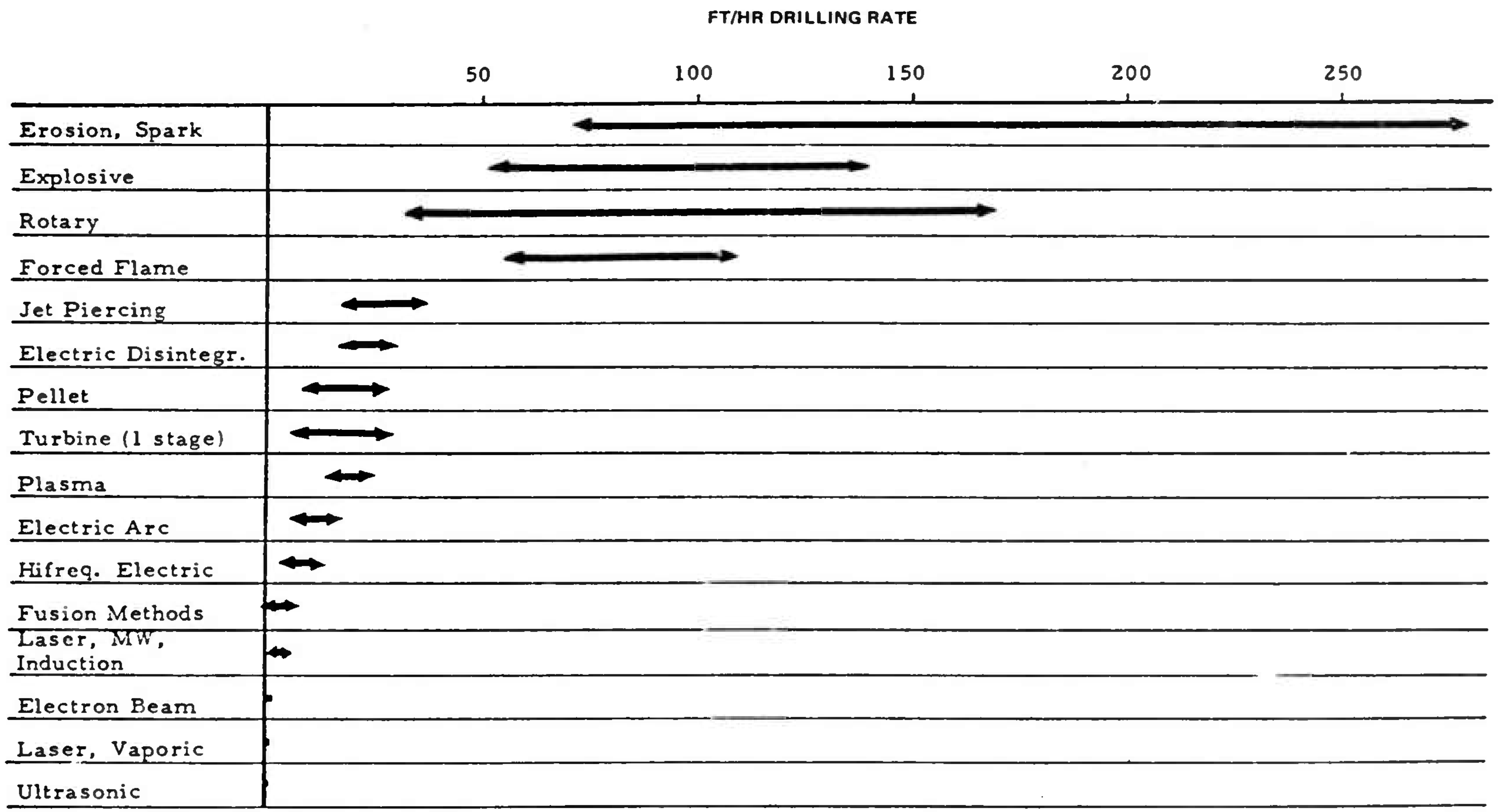
These round trips were performed with the same rig and crew. Therefore, they should be indicative of the length of round-trip time at 40,000 ft. Extrapolating the data, it takes 26-28 hr for 40,000 ft—assuming that drill bit life and other parameters can also be extended linearly (which, according to the literature, is not certain). Typically, the drill pipe is pulled and run in triple lengths of about 90 ft total, so that eleven stops and accelerations are required for every 1000 ft moved. Since the drill collars act on the hole walls like a piston in a cylinder, every dynamic effect on the drill pipe ultimately results in a force on the total exposed well.

It has been pointed out that the wells drilled in the shortest time not only cost the least but are usually the least troublesome. Extending the drilling time often compounds the severity of other problems, further increasing well costs. Therefore, one of the foremost goals in deep well drilling must be to shorten drilling time.

Drilling Rate Vs. Overall Drill Time

There are several ways in which the rate of progress can be improved. This becomes clear when one realizes that operational drill speeds in penetration tests, using rotary and other methods, are about 30-200 ft/hr and more in medium strength rock. Speeds of 10-30 ft/hr are attainable even by spalling and other techniques (Figure B-4). Water jets have drilled in controlled field tests with rates of 50-280 ft/hr (Figure B-5). Effective drill speeds of API classified drill bits range from 135-700 ft/hr. Yet, despite such high rates of drilling penetration, actual effective hole completion rates are much slower.

The Lone Star well in Oklahoma took 540 days to complete, with an average drilling



Mauer, W.C.; Heilhecker, J.K.; and Love, W.W., "High Pressure Jet Drilling," SPE-3988, Society of Petroleum Engineers, AIME, 1972.

Figure B-4. ESTIMATED NOVEL DRILLING RATES IN MEDIUM-STRENGTH ROCK

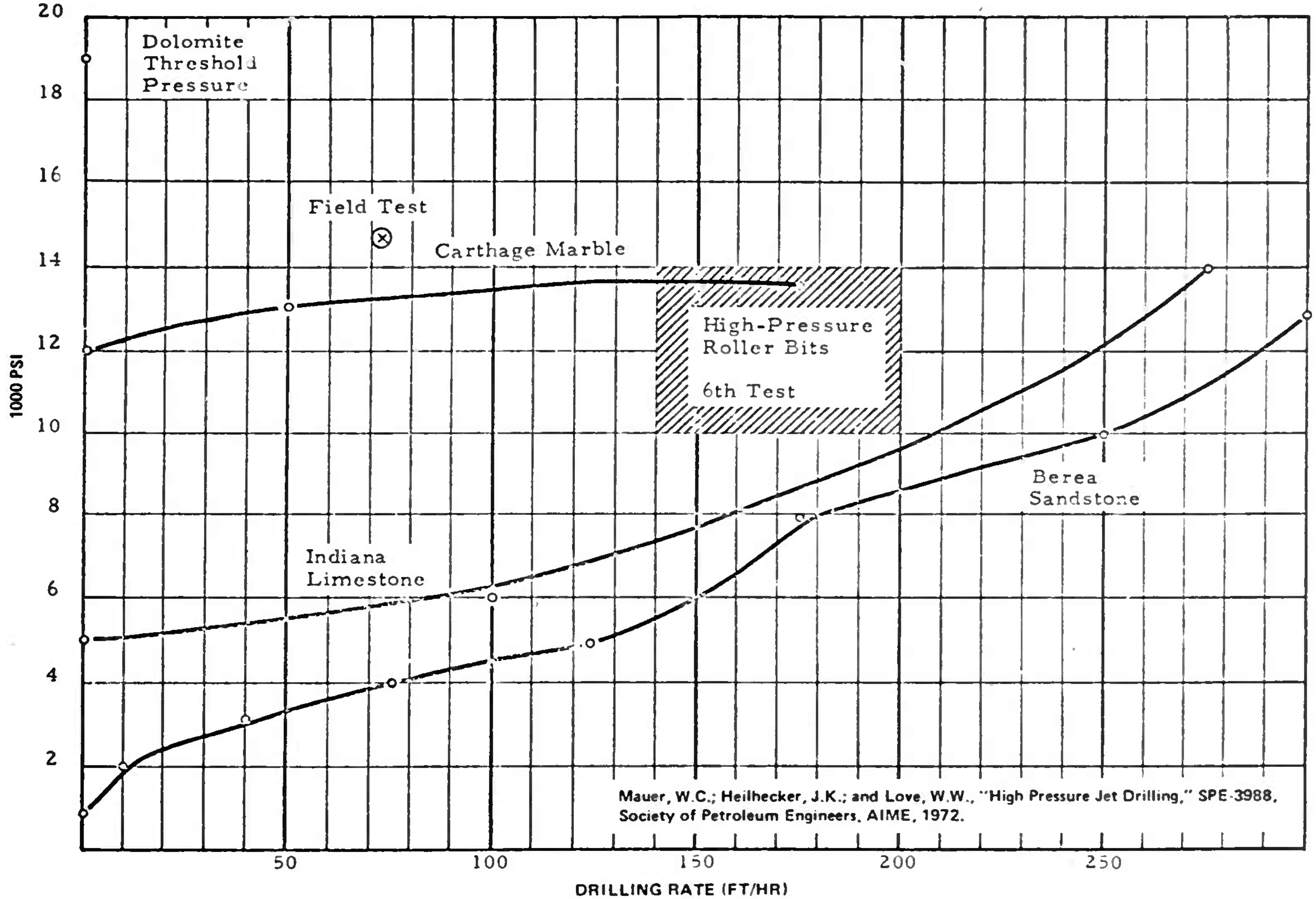


Figure B-5. WATER JET DRILLING

rate of 2.2 ft/hr. Some estimates are that a 40,000- to 50,000-ft well would take 5-7 yr to complete, with an average drilling rate of 0.8 ft/hr. Even if such an estimate should prove wrong, drilling would probably take at least half that time, depending on the location. Obviously, in ventures of such large drill time and distance, even minor improvements of the effective drilling rate can lead to enormous savings.

The N x 1000 Ft Drill Pipe Segment

In deep ocean drilling, it was suggested that long drill strings could be hung in the moor pool of the ship, thus minimizing trip time. In land drilling, large segments of drill pipe can be pulled intact, provided the derrick is tall enough; the pipe can be flexed or rolled; or the derrick can be extended at depth by a shaft that is accessible at bottom to man or equipment. To date these have not been done. However, mud head problems could probably be overcome by mud density manipulations or by mechanical means.

However, increased trip speed is dependent on pore pressure, viscosity of the drilling fluid, suitability of drill collars, and related parameters which must be coordinated to avoid dynamic disturbances affecting the stability of the hole.

A time line of the effect of shortened trip time in a drilling operation will be given later. At 30,000 ft, one round trip constitutes a time demand of about one day (22 hr). At greater depth, the time is likely to increase to 1-2 days. Since bit life decreases with increased temperature and pressure, causing an even greater need for increased tripping, it is conceivable that about 50 percent of the total rig time at depth near 40,000-50,000 ft will be spent in conventional tripping. Therefore, a re-design of the drill pipe handling may well be the most decisive factor in affecting total drill time and cost. A suggested solution is offered in Figure B-6.

At well depths of 45,000 ft, about 28 hr would be spent per trip, assuming average pipe motion. Handling long, multiple lengths of pipe can decrease the trip time. Very large sections of about 1000 ft (since they could be moved in deep water, assuming automatic coupling to be available, or by using a shaft) may decrease the trip time to 8-16 hr by saving coupling/decoupling time and allowing constant speeds for intervals of thousands of feet (assuming mud problems can be solved). (This constant driving speed may also be beneficial for the entire well.) Further savings in trip time can only be realized by increased trip speed. Trip surge calculations for one well are in the range of 1-6 ft/sec with resulting, acceptable pressures in equivalent mud weight (see page B-19). For example, to move 45,000 ft of string, with a few negligible stops, in 6-hr would take a constant velocity of 2.1 ft/sec. A 5-hr trip time appears attainable, assuming improved drill collar designs and matching mud/pore pressure balances. At that time, 80 percent of the total trip time, or 40 percent of the rig time, potentially can be saved. If only a fraction of this savings could be converted into

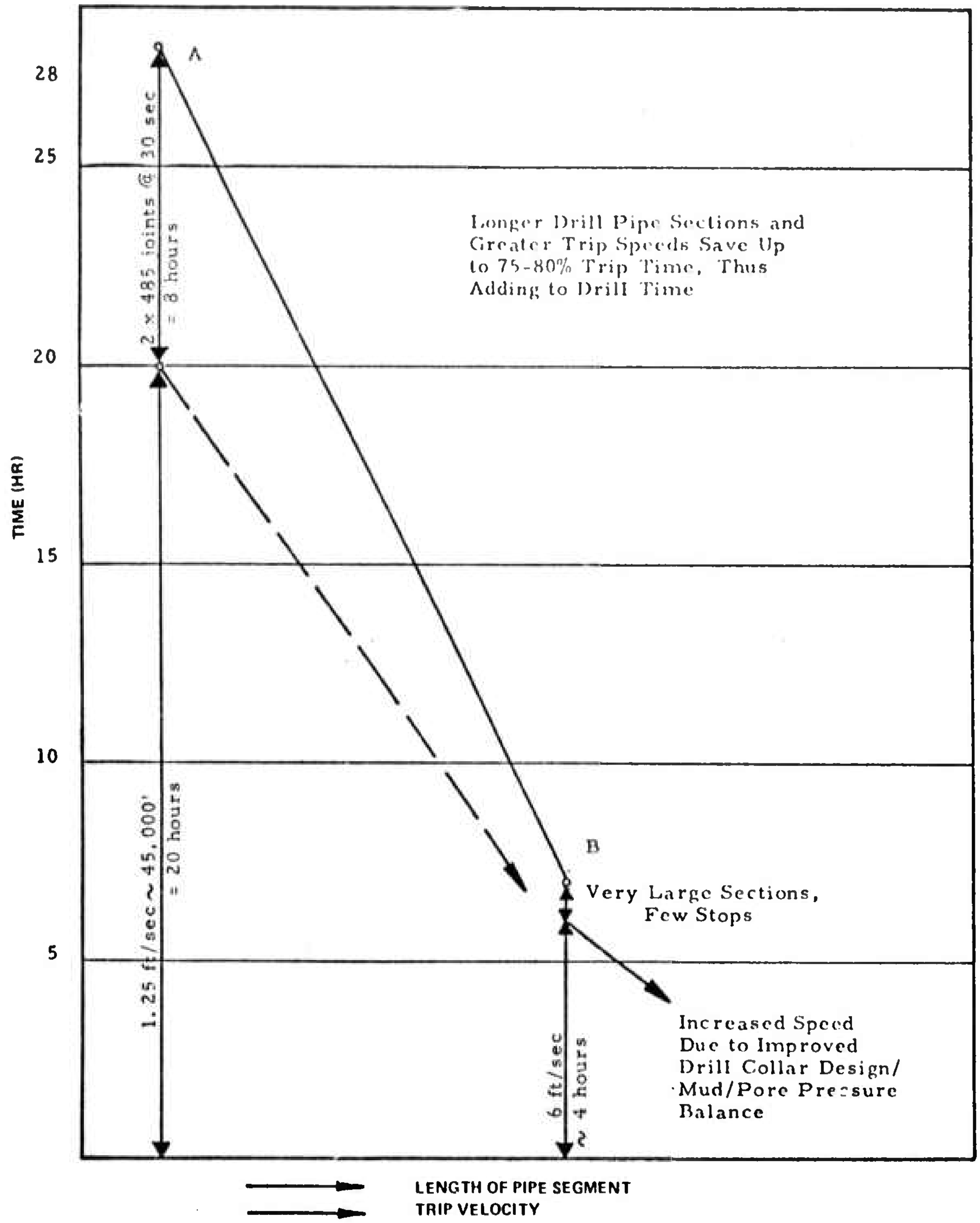


Figure B-6. DRILL STRING TRIP TIME AT A DEPTH OF 45,000 FT

active drill time, rotary total drill yields could be increased tenfold, from 2 to 20 percent of total rig time, or from 2 to 20 ft/hr overall effective drilling. Such increases appear entirely feasible without any major breakthrough. The potential cost savings per ultra-deep well are in the millions to ten millions of dollars.

A well-organized 228-day drilling operation, drilled by Falcon-Seaboard Drilling Co. for Amerada-Hess in Victoria County, Texas, reached 23,884 ft in soft to medium hard, hot rock and passed into 520°F temperatures. The average drill speed was 4.3 ft/hr, and the time table (Table B-6) shows that only 20 percent of the rig time was spent on trips; 50 percent drilling and reaming; 8 percent each on maintenance and revision of equipment and on logging and coring; and another 8 percent on casing and cementing. The high-temperature drilling operation utilized refrigerated mud (see the mud record shown in Figure B-9).

A combination of a high-capacity derrick and a wide-diameter well or shaft could be utilized to increase the effective drill time of a modern drill rig about tenfold, thereby reducing costs and technical drilling problems. The costs and technical problems to be expected by such combination are being investigated further.

Drilling Muds

Currently, there are two basic types of drilling muds. The most common is the water-base fluid. However, in many deep, hot wells, an oil-base fluid is used because of its stability at higher temperatures. Research is currently being performed at the three major mud company research centers in Houston, Texas, as well as in major oil company research centers. The objective is to develop drilling fluids to be used in deep wells with bottom hole temperatures in excess of 700°F.

The main problem with drilling fluids at high temperatures is that they tend to thicken or solidify at the bottom of a deep well during a round trip. Some of the various possible solutions to this problem are

- new highly stable polymer water-base muds,
- new oil-base muds,
- surface refrigeration of the drilling fluids, and
- faster trip times.

Any new drilling fluid developed for drilling to 40,000-50,000 ft must have the qualities that enable it to stabilize the well bore, remove the cuttings from the well, retain rheological properties for optimum hydraulics, and withstand contaminants.

The role of drilling muds and drilling fluids in deep wells has been discussed by Gray and Young* of Baroid/National Lead Company. They are advocating ways to maximize penetration rate and minimize nondrilling time. Drilling fluids of 2.34 gm/cm^3 specific gravity, stable at temperatures of 750°F and higher, are proposed using suspensions of heavy minerals in temperature-stable oily liquids. Oil mud will also cut down corrosion of drill pipe, and reduce stress corrosion failure.

Pore pressure to be found at maximum depth may range from 22,000 to 50,000 psi. Temperatures may range from 500° to 1000°F. Rocks, under these conditions, may have begun metamorphism and recrystallization. Tests by Handin *et al.*† on various sedimentary rocks indicate that a reduction of effective stress (formation pressure approaching overburden pressure) and an increase in temperature reduced the ultimate rock strength. (Furthermore, tests on marble at higher temperature showed a pronounced decrease in ultimate strength between 570° and 930°F.) At greater depths, borehole stability will become an increasingly more difficult problem. Rocks become weaker, but also more ductile and difficult to drill.

The long intervals of open hole made necessary by deep drilling place special emphasis on the problems of high torque and stuck pipe. Both problems are related to mud properties, although no specific measurements are made routinely to define the optimum characteristics. Torque reduction in water muds has been brought about by the addition of extreme-pressure lubricants.

Because of the severity of differential sticking, which depends on the magnitude of the difference between the mud pressure and the pore pressure and on the area of contact and the friction between the pipe and the mud cake, efforts have been directed toward preventive measures. The area of contact between the pipe and the mud cake has been reduced through the use of special drill collars and stabilizers. Several additives have been proposed to reduce the friction between the pipe and the filter cake of water muds. The use of oil mud virtually eliminates the problem of stuck pipe because of the thin filter cake and the low coefficient of friction between the cake and the preferentially oil-wet steel.

Corrosion of drill pipe deserves special attention in deep holes because of the difficulties of fishing operations. Corrosive attack is accelerated at high temperatures. Not only do corrosive substances enter the mud from the formations drilled but also thermal degradation of common constituents of water muds may create a corrosive environment. A consistent program on monitoring and counteracting corrosive attack of drill pipe is necessary.

The temperature requirement eliminates consideration of water-base muds for ultra-deep drilling. The critical temperature of water is 705°F. The reactions of the normal components of water mud with one another and with the formations drilled definitely limit the usefulness of water mud at even lower temperatures.

*Gray, G.R., and Young, F.S., Jr., "Drilling Fluids for Deep Wells in the United States," *Proceedings of the Eighth World Petroleum Congress*, 1971.

†Handin, J., *et al.*, *American Association of Petroleum Geologists Bulletin* 47(5):717-55 (1963).

The forced selection of a nonaqueous continuous phase for the mud narrows the search for a stable liquid for high-temperature lubricants, hydraulic fluids, and heat-transfer liquids. Such liquids fall into the general classes of aromatic of polyphenyl ethers, aromatic or phosphate esters, and aromatic silicates, silanes and silicones, and possibly, certain naphthenic and paraffinic oil and halogenated hydrocarbon esters. The required suspending and sealing qualities may be supplied by carbon black and gellants for high-temperature greases. Current facilities for testing such compositions for use as drilling fluids are inadequate and these speculations are unsupported by any experimental performance tests.

Cements and Cementing

The equipment is available at present to cement any casing string in an ultra-deep well. However, the cementing materials will have to be improved. High temperatures cause two very serious problems with current cements. The first problem is that of "flash" setting or hardening of the cement before it is totally in place. A second problem is also caused by high temperatures. The high-temperature environment causes the cement to lose most of its compressive strength, referred to as "strength retrogression." In a oral communication, Mr. Dwight Smith, Halliburton Company, Duncan, Oklahoma, indicated that these problems will be overcome in the future through research and development.

Logging Tool Capability

The Falcon-Seaboard well provided interesting insights into the limitations of logging tools. Below 21,000 ft all logging tools were inoperable because of the high temperature, although high-temperature difficulties actually started at 15,000 ft. All-Teflon insulated cables were used below 12,000 ft to avoid trouble. Below 19,000 ft, where temperatures could not be controlled, even with the mud cooling system, logging was done by insulating the tool completely. The inverted oil emulsion mud used at this depth restricted the tool choice to gamma ray-neutron logging. But formation logging was not affected alone—even the deviation survey tools had to be altered to withstand high temperatures. It is believed that the highest temperature reached in drilling the Falcon-Seaboard well was 520°F and that logging tool difficulties became serious at temperatures above 400°F. Thus, considerable progress will be required in logging technology to make proper monitoring of ultra-deep wells possible, particularly since logging time availability will become shorter and shorter, in the interest of maintaining an open well.

Records of Two Outstanding Drilling Operations

Figures B-7 and B-8 present performance records of two outstanding wells—the Falcon-Seaboard "Tally" well (which encountered 520°F temperatures) and the Baden No. 1 well (which exceeded 30,000 ft), respectively. Figure B-8 indicates mud weights, bits used, and major activities during the 228-day effort on the Tally well, including the total temperature history of the well, and offers a comparison of projected and actual drilling records. Figure B-9 shows the cooling system record used in the Tally well, which was largely responsible for the effective completion of the project despite temperatures of 520°F.

Optimized Drilling

Tables B-7 through B-11 give examples of computer programs which make such projections and completions as exemplified in Figures B-7 and B-8 possible. Shown are the Amoco Optimum Drilling program library (Table B-7), casing design (Table B-8), trip surge calculations (Table B-9), optimum drilling hydraulics (Table B-10), and well kick control instructions (Table B-11). The trip surge calculations show the limitations to drill string velocity, translated into equivalent mud weight. Other tables indicate the intricate interrelationship between hardware and operating parameters, which must be balanced by the drilling engineer for optimum performance. Figure B-10 indicates the dependence of equivalent mud gradient, pit gain volume and casing backpressure on the rate of mud pumpage. Both the bubble volume and backpressure required peak at a mud rate of 2150 bbl for this example. The use of such programs and qualified on-site drilling engineers will reduce the overall drilling times and costs for ultra-deep wells.

Table B-12 shows a typical recommended optimum drilling bit program. The bit series conforms to the new API classifications. Amoco's *Op Drilling* program—developed through nearly a decade of research and field application—can minimize the capital risk in drilling a well. Field results indicate that the actual home-making costs were reduced 15-20 percent when optimization programs were properly applied.

When a well is to be optimized, the *Op Drilling* program draws on an extensive data bank of drilling and geological information from many of the nation's oil productive areas. This extensive and expanding data bank is the key; it is the experience base on which optimized drilling is built. The data bank allows computer programs to calculate and optimize the maximum number of variables in drilling a given well.

From this data bank, Amoco's program selects wells and conditions as close as possible to the proposed well. The selected data are then computerized to prepare a predrilling plan

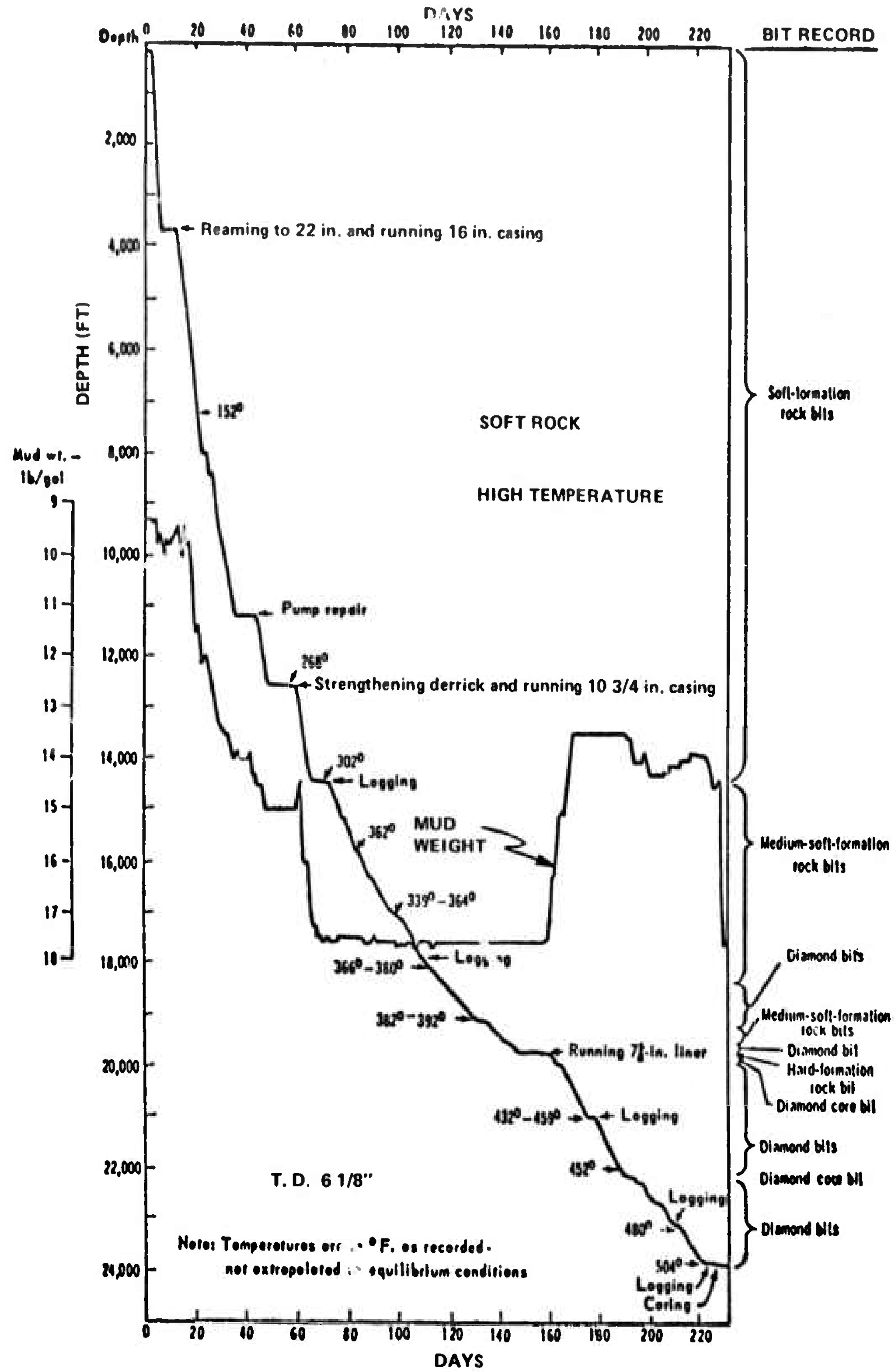
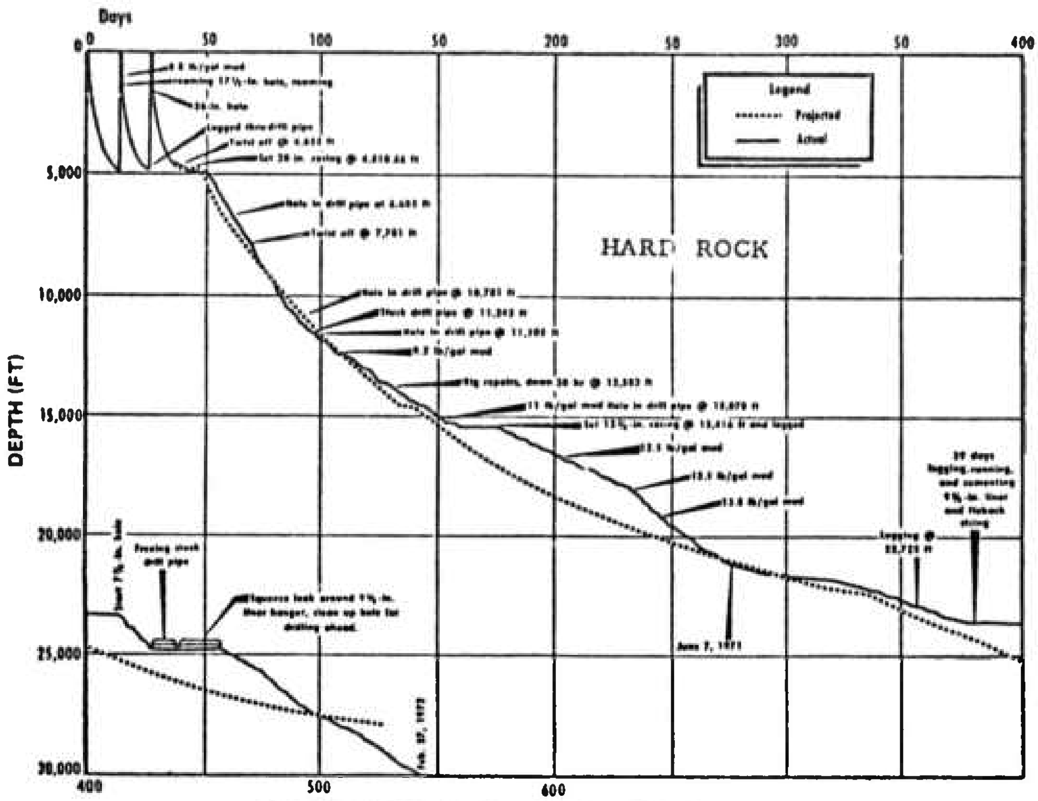


Figure B-7. DRILLING CURVE AMERADA PETROLEUM CORP'S 1 R.F. TALLY



BOTTOM TEMPERATURE 427° F AT 30,050 FT

T. D. 7 7/8''

Figure B-8. PERFORMANCE ON RECORD HOLE

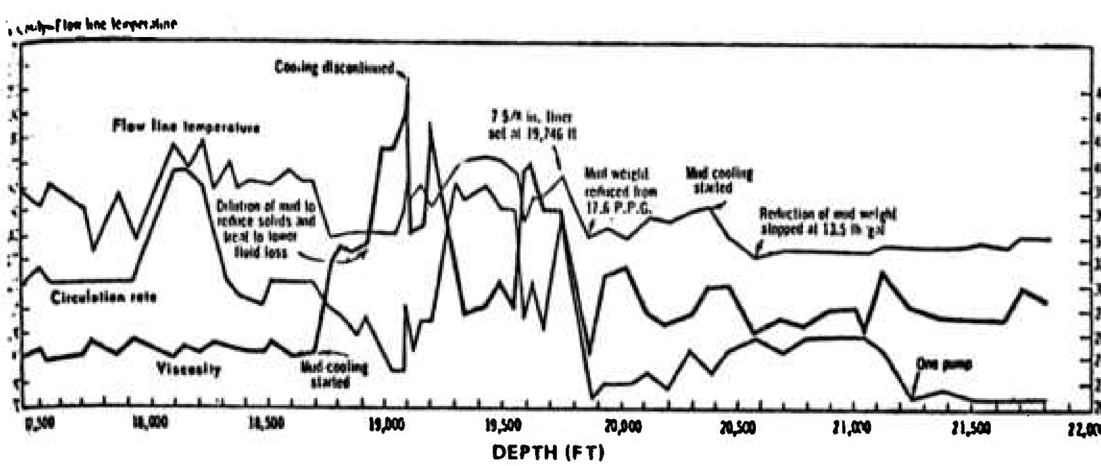


Figure B-9. MUD COOLING SYSTEM PERFORMANCE

Table B-7. OPTIMUM DRILLING PROGRAM LIBRARY

ID:BAE TETRA TECH

OPTION?LIBRARY

THE AVAILABLE LIBRARY PROGRAMS ARE AS FOLLOWS:

ASSEMBLY	:	BOTTOM HOLE ASSEMBLY RATING – RIGIDITY, STICKABILITY, FISHABILITY.
BUTTON	:	COMPARES MILL-TOOTH BITS WITH AN INSERT BIT.
CASING	:	DESIGNS CASING FROM EITHER U.S. OR CANADIAN STOCKS.
CNTRFUGE	:	TENTATIVE API STANDARD EVALUATION PROCEDURE FOR CENTRIFUGAL SEPARATORS.
COST.SUM	:	IDENTIFYS AND PRICES BITS. ALSO COMPUTES COST PER FOOT, TRIP TIMES AND NET DAYS FOR A SINGLE BIT OR AN INTERVAL.
CYCLONE	:	TENTATIVE API STANDARD EVALUATION PROCEDURE FOR HYDROCYCLONES.
DEVPLOT	:	DEVIATION SURVEY CALCULATIONS AND PLOTTING – EITHER TANGENTIAL (ENGINEER TYPE) OR BALANCED (MODERN, ACCURATE) CALCULATIONS.
DIABIT	:	COMPARES MILL-TOOTH BITS WITH A DIAMOND BIT.
DRILLOFF	:	DRILL-OFF TEST TO DETERMINE ACTUAL OPTIMUM WEIGHT-ON-BIT.
HYDRAUL	:	OPTIMIZED RIG HYDRAULICS FOR DRILLING.
HYD.ANAL	:	COMPUTES CONDITIONS FOR THE ANALYSIS OF THE DRILLING HYDRAULICS FOR A PARTICULAR BIT RUN.
KICK	:	GIVES IADC CONSISTENT INSTRUCTIONS FOR PREVENTING A KICK FROM BECOMING A BLOWOUT.
MUDADD	:	CALCULATES COST TO TREAT AND MAINTAIN A MUD SYSTEM WITH SPECIFIC PRODUCTS.
MUDHY	:	EFFECTS OF MUD AND HYDRAULICS ON PENETRATION RATE AND DRILLING COST.
PLATPLNE	:	CALCULATES & PLOTS RELATIVE LOCATIONS OF MULTIPLE WELLS BELOW A PLATFORM.
RIGSEL	:	COMPARES THE CAPABILITIES AND PROBABLE COSTS TO DRILL A WELL WITH THREE DIFFERENT RIGS.
SHAKER	:	TENTATIVE API STANDARD EVALUATION PROCEDURE FOR VIBRATING SCREENS.
SHOEFRAC	:	CALCULATES FRACTURE CONDITIONS AND CASING DEPTH REQUIREMENTS FOR OFFSHORE OPERATIONS.
SURGE	:	PRESSURE SURGE AND PIPE LOWERING SPEEDS, BOTH HYDRAULIC AND INPACT DYNAMIC FORCES.
WTRPM	:	BEST BIT WEIGHT AND ROTARY SPEED TO DRILL A PARTICULAR SECTION.

Table B-8. CASING DESIGN

OPTION?CASING

03/07/73

CANADIAN VERSION (1) OR AMERICAN VERSION (2) WHICH ?2

UNRESTRICTED FIRST RUN (1) OR ALTERNATIVES (2) WHICH ?1

COLLAPSE = 1. BURST = 1. TENSION = 1.6

CASING SIZE, CASING DEPTH . . . . ?5,17000

CASING JOINT LENGTH, MUD WEIGHT . . . . ?40,10

WISH TO LIMIT CASING SEGMENT LENGTH (1 = YES, 0 = NO) . . . . ?0

DO YOU WISH TO PUT A LIMITING PRESSURE ON BURST DESIGN (1 = YES, 0 = NO) ?1

INPUT MINIMUM DESIGN PRESSURE . . . . ?5000

DO YOU WISH TO USE UP PRESENT INVENTORY (1 = YES, 0 = NO) . . . . ?0

CASING DESIGN PROGRAM

MUD WEIGHT	10.000	
HYDROSTATIC PRES.	8830.	
DESIGN PRESSURE	5000.	
CASING SIZE	5.000	IN
CASING DEPTH	17000.	
BURST FACTOR	1.000	
COLLAPSE FACTOR	1.000	
TENSION FACTOR	1.600	

DEPTH		WT			CASING DESC.		CASING COST	FACTOR		FACTOR
FROM	TO	FT	ACC	WT	TYPE	JOINT		COLL	BURST	TENSION
17000	10182	6818	122	18.0	N80	LT&C	23503.42	1.00	1.92	3.23
10182	5405	4777	194	15.0	N80	LT&C	37229.75	1.07	1.57	1.60
5405	2453	2952	247	18.0	N80	LT&C	47404.91	1.44	2.03	1.60
2453	1759	694	260	18.0	C95	LT&C	50387.43	1.58	2.41	1.60
1759	40	1719	290	18.0	P110	LT&C	57796.61	1.87	2.79	1.70
LAST JOINT TENSION FACTOR INSUFFICIENT USE JOINT OF ABOVE										
40	0	40	291	18.0	N80	LT&C	57934.52	1.87	2.79	1.36

SMALLEST DRIFT AND INTERNAL DIAMETERS 4.15 4.28

MAX EXTERNAL DIAMETER: 5.56
DO YOU WISH TO STOP PRINT(1), PROCEED WITH OPTIONS PRINT(0) ?1

OPTION?AMF

OFF AT 11:58CST 04/01/73

Table B-9. TRIP SURGE CALCULATIONS

OPTION?SURGE

PRESSURE SURGE CAUSED BY TRIP; BOTH HYDRAULIC AND INPACT.
721121

DRILL PIPE OD, TOOL JOINT OD . . . . ?5.5, 7.3
SPECIAL DRILL PIPE LENGTH . . . . ?0
NUMBER OF COLLARS BOTTOM SET, COLLAR OD . . . . ?20, 8
NUMBER OF COLLARS TOP SET, COLLAR OD . . . . ?10, 7
BIT DIAMETER . . . . ?12.25
DEPTH CASING SET, CASING ID . . . . ?13000, 13.375
DEPTH LINER SET, LINER ID . . . . ?0, 0
MUD WEIGHT, PV, YV . . . . ?10, 0, 0
WAS MUD DISPERSED (1 = YES, 0 = NO) . . . . ?1
DEPTH OF BIT . . . . ?12000
GREATER DANGER OF FRACTURE WHEN BELOW CASING – INCREASE BIT DEPTH
DEPTH OF BIT . . . . ?18000
PRESSURES REQUIRED TO FRACTURE FOR NORMAL AND ABNORMAL GRADIENTS ARE
17139. PSI-TO 17264. PSI •
JETS, IN 32ND'S (EG. 10, 10, 10)?13, 13, 13

-TRIP SPEED- SEC.PER CENTER JOINT	FT. PER SEC.	DISPLACED MUD GPM.	-PRESSURE- SURGE PSI.	AT BIT	EQUIVALENT MUD WT.
25.	1.20	184.L	38.	9389.	10.0
20.	1.50	231.L	38.	9389.	10.0
16.	1.87	290.L	39.	9390.	10.0
12.	2.50	388.L	41.	9392.	10.0
9.	3.33	518.T	43.	9394.	10.0
7.	4.29	667.T	48.	9399.	10.1
5.	6.00	935.T	57.	9408.	10.1

STOP (0), NEW DEPTH (1), NEW RUN (2)?1

DEPTH OF BIT . . . . ?13000

PRESSURES REQUIRED TO FRACTURE FOR NORMAL AND ABNORMAL GRADIENTS ARE
11729. PSI-TO 11844. PSI •

JETS, IN 32ND'S (EG. 10, 10, 10)?13, 13, 13

-TRIP SPEED- SEC.PER CENTER JOINT	FT. PER SEC.	DISPLACED MUD GPM.	-PRESSURE- SURGE PSI.	AT BIT	EQUIVALENT MUD WT.
25.	1.20	185.L	26.	6779.	10.0
20.	1.50	232.L	26.	6780.	10.0
16.	1.87	290.L	27.	6780.	10.0
12.	2.50	388.L	28.	6781.	10.0
9.	3.33	519.T	29.	6782.	10.0
7.	4.29	668.T	30.	6784.	10.0
5.	6.00	936.T	35.	6788.	10.1

STOP (0), NEW DEPTH (1), NEW RUN (2)?0

Table B-10. OPTIMUM DRILLING HYDRAULICS

OPTION?HYDRAUL

721207
HYDRAULICS CALCULATIONS WITH EITHER MINIMUM DATA (ASSUMING TYPICAL STRING AND MUD PROPERTIES) OR DETAILED DATA (IN WHICH YOU SHOULD TYPE (0) FOR UNKNOWNS)

BIT SIZE, MAXIMUM PUMP PRESSURE, MAX FLOW RATE?12.25, 3500, 800

TOTAL DATA RUN TYPE (0) MINIMUM DATA TYPE (1) . . . ?0

DRILL PIPE OD, ID, TOOL JOINT OD, ID . . ?5.5, 0, 0, 0

NUMBER OF COLLARS TOP SET, COLLAR OD, ID . . ?10, 7, 0

MUD WEIGHT, PV, YV ?10, 0, 0

WAS MUD DISPERSED (1 = YES, 0 = NO) . . ?1

JETS, 2 OR 3, OR (0) WILL OPTIMIZE?0

HOLE SIZE 12.25 DP 5.5 X 4.67 TJ 7.33 X 3.97

300.FT OF COLLARS 7.00 X 2.42 AND 600.FT 8.00 X 2.60

MUD WT.10.0 PV 12. YV 4.

DEPTH?20000

153.PSI TO START CIRC. (PIPE ROTATING) 10.1 # /GAL.ECG AT 520.GPM

PRESSURE 3500.

REAL GPM	ANNULUS VEL.	CHIP RATE	REC. JETS	JET VEL.	HP/ SQIN	% BIT	PUMP MECH HP	
480.	98.PP	77	12 12 13	439	4.3	52	1153	
500.	102.PP	83	12 13 13	434	4.3	49	1201	
520.	106.PT	88	13 13 13	429	4.3	47	1249	RECOMMENDED
540.	110.PT	93	13 14 14	403	4.0	42	1297	
560.	115.PT	99	14 14 15	380	3.7	38	1345	

JET HP LIMITED TO 4.3 BY 3500.PSI
GPM ALTERED TO AVOID TURBULENCE OR INCREASE HP

WANT. . NEW HOLE (1), CHANGE STRING (2), CHANGE MUD (3), CHANGE DEPTH (4), STOP (5) . . . WHICH (1 TO 5)?5

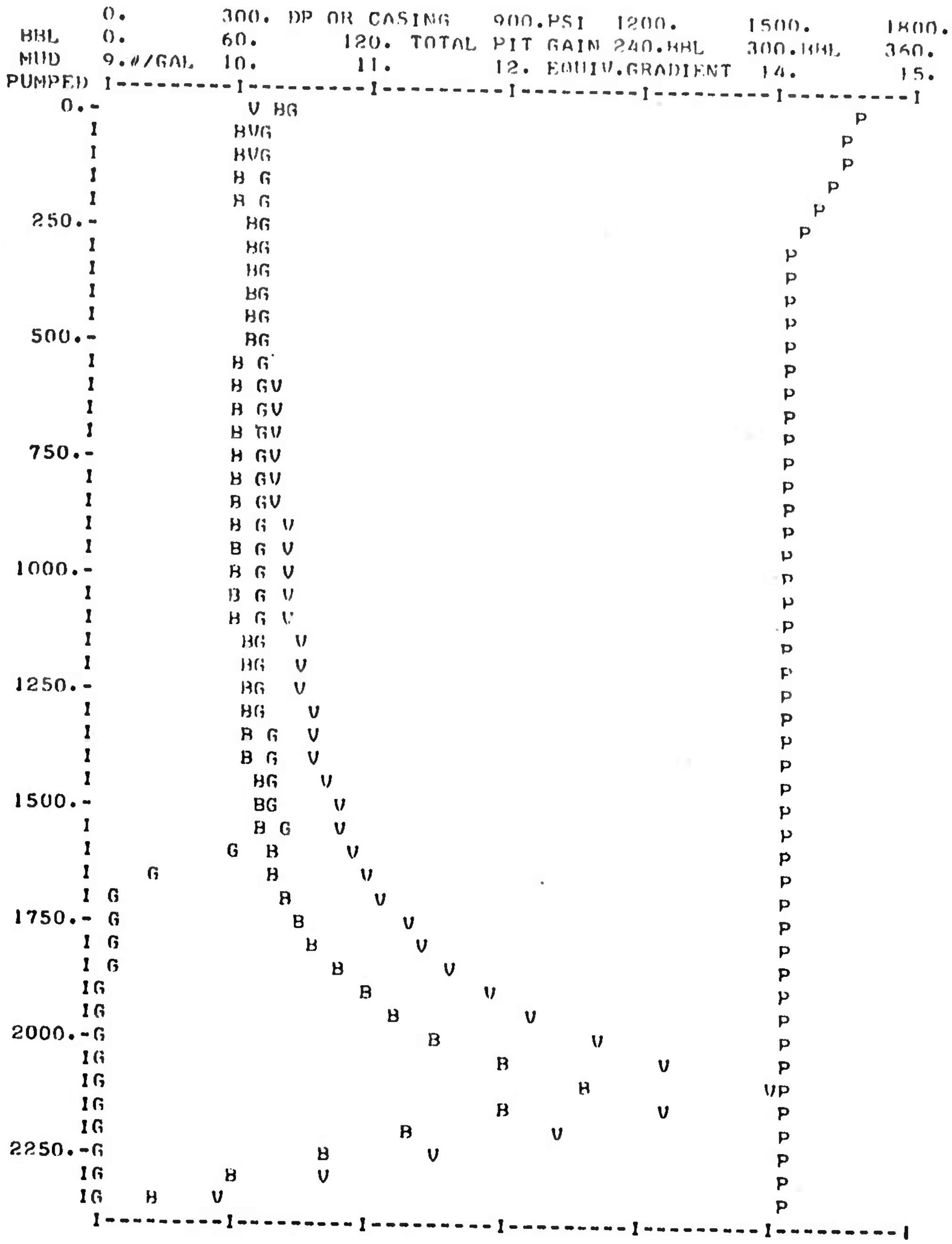
Table B-11. WELL KICK CONTROL INSTRUCTIONS

```
ID:TETRA TECH

OPTION?KICK

THIS PROGRAM DIRECTLY CALCULATES EITHER THE *DRILLERS METHOD* (CIRCULATE GAS OUT WITH
PRESENT MUD- SIMPLE, AND SAFEST FROM LOST CIRCULATION) OR THE *WAIT & WEIGHT METHOD* IN
WHICH WEIGHTED MUD IS PUMPED IN AS SOON AS POSSIBLE TO KILL THE WELL IN ONE CIRCULATION.
OCT. 23, 72

HOLE SIZE, DRILL PIPE OD    ?12.25, 5

NO. COLLARS, COLLAR OD?21, 8

                12.25 HOLE
                 5.00 INCH DRILL PIPE
                 630. FEET          8.00 COLLARS

LAST CASING SET AT WHAT DEPTH?6000

DEPTH, MUD WEIGHT AT TIME OF KICK?20000, 9.2

SHUT-IN DP PSI, CASING PSI, PIT GAIN (OR 0)?100, 400, 10

9.30 PPG MUD WEIGHT REQUIRED

WHAT MUD WEIGHT WILL YOU USE, AND HOW MANY BARRELS WILL YOU PUMP BEFORE GETTING IT
STARTED IN (0, 0 FOR DRILLERS METHOD)
 ?9.4, 0

FORMATION PRESSURE    9658.

INFLOW VOLUME, IF GAS      70.62 BBL
ASSUME GAS KICK!
APPARENT FLUID DENSITY    1.8#/GAL

PIPE VOLUME 358. ANNULUS  2406.  TOTAL  2763.

SMOOTH OUT PUMP, RECORD SPEED AND DP PRESSURE, AND USE CONSTANT DP CONTROL BEFORE
PUMPING   1600. BBL.

PEAK PRESSURE  1087.  WHEN GAS HITS SURFACE AFTER PUMPING  2109. BBL.

MAXIMUM MUD GRADIENT AT CASING SHOE  10.5
AFTER PUMPING  0. BBL.

FOR PLOT TYPE (1), FOR DATA POINTS TYPE (2), OTHERWISE TYPE (0)?2

WHAT PUMP RATE DO YOU INTEND TO USE? WHAT IS THE NORMAL EXPECTED DRILL PIPE PRESSURE AT
THIS RATE? SPM, PSI  (OR 0, 0)?350, ← ← ← ← 60, 1600
```

BBL MUD PUMPED	DP PSI AT 60. SPM	VOL. OF GAS	CASING PSI REQ'D	EQUIVALENT MUD GRADIENT AT CASING SHOE
0.	1700.	71.	400.	10.5
50.	1676.	71.	328.	10.3
100.	1653.	72.	325.	10.2
150.	1629.	72.	328.	10.3
200.	1605.	73.	330.	10.3
250.	1582.	74.	332.	10.3
300.	1558.	74.	334.	10.3
350.	1534.	75.	337.	10.3
400.	1531.	75.	334.	10.3
450.	1531.	76.	332.	10.3
500.	1531.	77.	331.	10.3
550.	1531.	78.	330.	10.3
600.	1531.	78.	329.	10.3
650.	1531.	79.	328.	10.3
700.	1531.	80.	327.	10.2
750.	1531.	81.	326.	10.2
800.	1531.	82.	326.	10.2
850.	1531.	83.	326.	10.2
900.	1531.	84.	326.	10.2
950.	1531.	85.	326.	10.2
1000.	1531.	87.	327.	10.2
1050.	1531.	88.	328.	10.3
1100.	1531.	90.	329.	10.3
1150.	1531.	91.	331.	10.3
1200.	1531.	93.	334.	10.3
1250.	1531.	95.	337.	10.3
1300.	1531.	97.	341.	10.3
1350.	1531.	99.	346.	10.3
1400.	1531.	102.	352.	10.3
1450.	1531.	105.	360.	10.4
1500.	1531.	109.	370.	10.4
1550.	1531.	113.	383.	10.4
1600.	1531.	118.	398.	10.1
1650.	1531.	124.	416.	9.4
1700.	1531.	131.	440.	9.1
1750.	1531.	139.	468.	9.1
1800.	1531.	149.	504.	9.1
1850.	1531.	162.	549.	9.1
1900.	1531.	177.	605.	9.1
1950.	1531.	197.	679.	9.1
2000.	1531.	222.	775.	9.1
2050.	1531.	256.	905.	9.1
2100.	1531.	304.	1087.	9.1
2150.	1531.	256.	904.	9.1
2200.	1531.	206.	712.	9.1
2250.	1531.	156.	520.	9.1
2300.	1531.	106.	329.	9.1
2350.	1531.	56.	137.	9.1

FOR PLOT TYPE (1), OTHERWISE (0)?1

P - DRILL PIPE PRESSURE AT 60.SPM
B - BACKPRESSURE REQUIRED ON CASING
V - PIT GAIN VOLUME (BUBBLE VOLUME)
G - EQUIVALENT MUD GRADIENT AT CASING SHOE,LB/GAL



FOR DATA POINTS TYPE (1), OTHERWISE (0)?0

TO STOP TYPE (0), FOR NEW WELL(1), FOR NEW CONDITIONS(2)?0

Figure B-10. DEPENDENCE OF EQUIVALENT MUD GRADIENT, PET GAIN VOLUME, AND CASING BACKPRESSURE ON MUD PUMPAGE RATE

Table B-12. OPTIMUM RECOMMENDED BIT PROGRAM

Bit No.	Size	Bit Series	Depth Out	Footage	Hr	Ft/hr	Weight	rpm	Ref. No.
2	9.875	1-1	6,200	2200	16	135	40	180	2
3		1-1	7,800	1600	15	110	40	150	3
4		1-2	8,300	500	10	50	35	150	4
5		1-1	8,900	600	13	45	40	140	5
6		1-1	9,350	450	11	40	30	140	6
7		1-1	9,700	350	11	32	30	130	7
8		1-1	10,100	400	10	40	40	100	8
9		5-2	11,100	1000	60	16	35	50/55	9-12
10		5-2	12,100	1000	60	16	35	50/55	13-15
11		5-2J	12,900	800	65	12	35	45/50	16-19
12		5-2J	13,500	600	65	9	35	45/50	20-22
13		5-2J	13,950	450	65	7	35	45/50	23-26
14		5-2J	14,300	450	65	7	35	45/50	27-30

outlining the most economical and efficient methods to be used for drilling a given well. The program recommends a combination of drilling variables such as weight on the bit, rotary speed, mud characteristics, and bit selection. The driller, by following the prescribed plan, can cut costs and time and substantially increase drilling efficiency.

An example of the achievable savings is given in Figure B-11, which shows what can be accomplished by the application of optimization procedures. Curve "A" represents the actual results the contractor experienced in the field prior to using an optimized drilling program. Curve "C" represents the recommended optimum program and Curve "B" shows actual results of following the optimized drilling plan.

Presently Amoco is offering the program to drilling contractors and outside operators on a priority basis and for a minimal fee under an *Op Drilling* service agreement. The company's ultimate goal is to make optimized drilling techniques available throughout the industry. Any location within the contiguous United States will be considered as a possible site for an optimization program. Optimization programs are now available for rigs ranging from 5,000-ft depth ratings to the largest in the world. No special rig modifications are needed to use these programs.

Amoco's package program, now in use, consists of six integral parts:

1. a predrilling conference;
2. initial recommendations marked on an adjusted log;
3. computer printouts of hydraulics, weight, and rotary speed for optimum control on location;

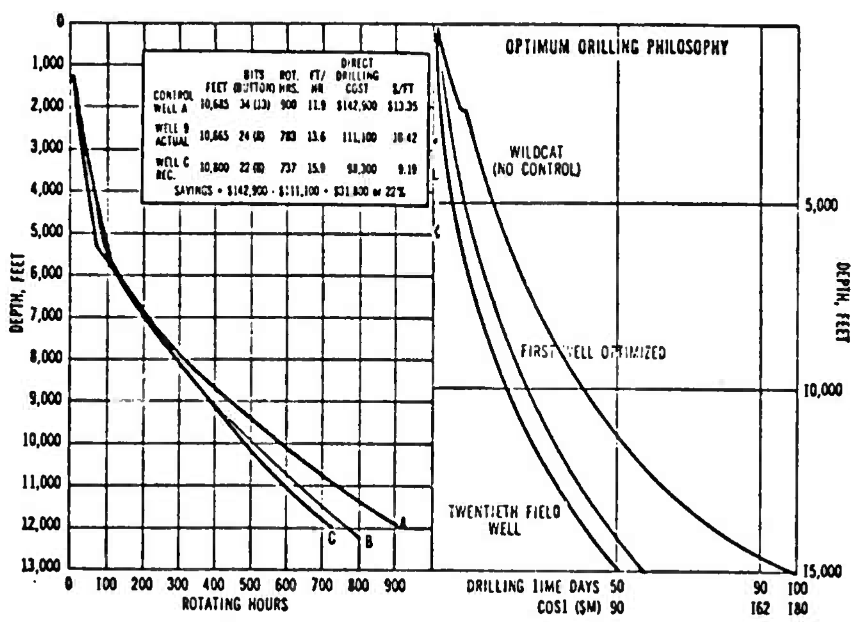


Figure B-11. OPTIMUM DRILLING

4. computer-generated blowout control tables;
5. intermediate analysis and re-computations if needed during drilling;
6. postanalysis.

In refining the optimized drilling program to its present form, Amoco research scientists and engineers conducted extensive drilling research, analyzed over 95,000 bit runs and optimized more than 400 Amoco wells.

Continental Oil Company used Amoco's program on two of its wells in eastern Montana. Drilling costs were reduced on these wells 30 percent and rig days were reduced approximately 33 percent. Two wells completed in western Oklahoma are being used to demonstrate *Op Drilling* programs in operation—Lone Star Producing Company and Glover, Hefner and Kennedy's Baden No. 1, drilled by Loffland Brothers, and Glover, Hefner and Kennedy's Miller No. 1, drilled by Helmerich and Payne. Prior to spudding, programs were calculated to help plan the drilling of each well.

At each well site, a Magcobar D.A.T.A. Unit, a product of Dresser Oilfield Products Division, monitors the drilling progress and gathers the data for the optimizing programs. The drilling data is then forwarded over teletype to Amoco. Amoco personnel analyze the data and forward them as input to a General Electric time-sharing computer in Los Angeles, where a permanent, up-to-date computer file of drilling data is maintained for the wells. The data are then merged with the Amoco programs also available on the computer.

The results of these calculations permit engineers to measure the effectiveness of the planned drilling program. Examination of the Los Angeles computer output also enables Amoco personnel to recommend changes, if necessary, in the drilling variables to improve drilling performance. This information is sent back to the well sites.

The graphical terminal, manufactured by Tektronix, Inc., displays updated graphs showing the actual drilling progress of the two wells and the progress as projected by the optimization plan. These graphs are generated in the General Electric time-sharing computer for display at the terminal. The two wells may also be plotted on the same graph for comparison.

A Tektronix hard-copy unit attached to the graphical display terminal can provide hard copies of the graphs at a push of a button and can display specialized graphs such as individual bit runs and well deviations. Certain real-time, decision-making computer programs used in *Op Drilling* can be used to provide specific answers to individual well design problems.